PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

February 14, 2020

VIA ELECTRONIC FILING

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

Attn: Filing Center

RE: Advice No. 20-001
Docket UE 374 – PacifiCorp's Request for General Rate Revision

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits for filing an original and 20 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, 2021. Electronic versions of the testimony, exhibits, and workpapers is provided on an electronic storage device.

Sheet	**Schedule**	**Title**
Fifth Revision of Sheet No. INDEX-2	Tariff Index	Table of Contents - Schedules
Twenty-Fourth Revision of Sheet No. INDEX-3	Tariff Index	Table of Contents - Schedules
Third Revision of Sheet No.4	Schedule 4	Residential Service Delivery Service
Third Revision of Sheet No.5	Schedule 5	Separately Metered Electric Vehicle Service for Residential Consumers Delivery Service
Original 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
Fourth Revision of Sheet No.15-1	Schedule 15	Outdoor Area Lighting Service – No New Service Delivery Service
Fourth Revision of Sheet No.23-1	Schedule 23	General Service – Small Nonresidential Delivery Service
Third Revision of Sheet No.28-1	Schedule 28	General Service Large Nonresidential 31KW to 200 KW Delivery Service
Original Sheet No. 29.1	Schedule 29	Pilot for General Service Time-Of-Use Delivery Service
Original Sheet No. 29.2	Schedule 29	Pilot for General Service Time-Of-Use Delivery Service

Sheet	Schedule	Title
Third Revision of Sheet No.30-1	Schedule 30	General Service Large Nonresidential 201 KW to 999 KW Delivery Service
Third Revision of Sheet No.41-1	Schedule 41	Agricultural Pumping Service Delivery Service
Third Revision of Sheet No.41-2	Schedule 41	Agricultural Pumping Service Delivery Service
Second Revision of Sheet No. 41-3	Schedule 41	Agricultural Pumping Service Delivery Service
First Revision of Sheet 45-2	Schedule 45	Public DC Fast Charger Optional Transitional Rate Delivery Service
Third Revision of Sheet No.47-1	Schedule 47	Large General Service Partial Requirements 1,000 KW and Over Delivery Service
Third Revision of Sheet No. 47-2	Schedule 47	Large General Service Partial Requirements 1,000 KW and Over Delivery Service
Fourth Revision of Sheet No.48-1	Schedule 48	Large General Service 1,000 KW and Over Delivery Service
Fifth Revision of Sheet No. 48-2	Schedule 48	Large General Service 1,000 KW and Over Delivery Service
CANCELED Second Revision of Sheet No.50-1	Schedule 50	Mercury Vapor Street Lighting Service No New Service Delivery Service
CANCELED Fourth Revision of Sheet No.50-2	Schedule 50	Mercury Vapor Street Lighting Service No New Service Delivery Service
Fourth Revision of Sheet No.51-1	Schedule 51	Street Lighting Service Company – Owned System Delivery Service
CANCELED Fourth Revision of Sheet No.52-1	Schedule 52	Street Lighting Service Company – Owned System No New Service Delivery Service
CANCELED First Revision of Sheet No.52-2	Schedule 52	Street Lighting Service Company – Owned System No New Service Delivery Service
Fourth Revision of Sheet No.53-1	Schedule 53	Street Lighting Service Consumer – Owned System Delivery Service
Fourth Revision of Sheet No.54-1	Schedule 54	Recreational Field Lighting – Restricted Delivery Service
Third Revision of Sheet No.76R-1	Schedule 76R	Large General Service – Partial Requirements Service Economic Replacement Power Rider Delivery Service
CANCELED Fourth Revision of Sheet No. 80	Schedule 80	Generation Investment Adjustment

Sheet	**Schedule**	**Title**
Twenty-Fourth Revision of Sheet No. 90	Schedule 90	Summary of Effective Rate Adjustments
Eleventh Revision of Sheet No. 91-1	Schedule 91	Low Income Bill Payment Assistance Fund
Twelfth Revision of Sheet No. 98	Schedule 98	Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act
First Revision of Sheet No. 125-1	Schedule 125	Commercial and Industrial Energy Services No New Service
CANCELED Original Sheet No. 196	Schedule 196	Adjustment to Remove Deer Creek Mine Investment From Rate Base
Original Sheet No. 197R	Schedule 197R	Generation Plant Removal Adjustment
Fifth Revision of Sheet No.200-1	Schedule 200	Base Supply Service
Fifth Revision of Sheet No.200-2	Schedule 200	Base Supply Service
Fifth Revision of Sheet No.200-3	Schedule 200	Base Supply Service
Eleventh Revision of Sheet No. 201-1	Schedule 201	Net Power Costs Cost-Based Supply Service
Eleventh Revision of Sheet No. 201-2	Schedule 201	Net Power Costs Cost-Based Supply Service
Eleventh Revision of Sheet No. 201-3	Schedule 201	Net Power Costs Cost-Based Supply Service
Sixth Revision of Sheet No. 202-1	Schedule 202	Renewable Adjustment Clause Supply Service Adjustment
Eighth Revision of Sheet No. 203	Schedule 203	Renewable Resource Deferral Supply Service Adjustment
Tenth Revision of Sheet No. 204	Schedule 204	Oregon Solar Incentive Program Deferral Supply Service Adjustment
Eighth Revision of Sheet No. 205-1	Schedule 205	TAM Adjustment for Other Revenues
Eighth Revision of Sheet No. 205-2	Schedule 205	TAM Adjustment for Other Revenues
Eighth 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
Third Revision of Sheet No. 210-1	Schedule 210	Portfolio Time-Of-Use Supply Service
Third Revision of Sheet No. 210-2	Schedule 210	Portfolio Time-Of-Use Supply Service
CANCELED Third Revision of Sheet No. 215-1	Schedule 215	Irrigation Time-Of-Use Pilot Supply Service
CANCELED Third Revision of Sheet No. 215-2	Schedule 215	Irrigation Time-Of-Use Pilot Supply Service
Original Sheet No. 218-1	Schedule 218	Interruptible Service Pilot
Original Sheet No. 218-2	Schedule 218	Interruptible Service Pilot
Original Sheet No. 219-1	Schedule 219	Real-Time Day Ahead Pricing Pilot
Original Sheet No. 219-2	Schedule 219	Real-Time Day Ahead Pricing Pilot

Sheet	**Schedule**	**Title**
Twelfth Revision of Sheet No. 220-1	Schedule 220	Standard Offer Supply Service Rate Mitigation Adjustment
Fourth Revision of Sheet 230	Schedule 230	Emergency Supply Service
Second Revision of Sheet No. 276R-2	Schedule 276R	Large General Service – Partial Requirements Service Economic Replacement Power Rider Supply Service
Second Revision of Sheet No. 293-1	Schedule 293	New Large Load Direct Access Program Cost of Service Opt-Out
Tenth Revision of Sheet No. 297-2	Schedule 297	Energy Conservation Charge
Third Revision of Sheet No. 299	Schedule 299	Rate Mitigation Adjustment
Third Revision of Sheet No.723-1	Schedule 723	General Service – Small Nonresidential Direct Access Delivery Service
Third Revision of Sheet No.728-1	Schedule 728	General Service Large Nonresidential 31 KW to 200 KW Direct Access Delivery Service
Third Revision of Sheet No.730-1	Schedule 730	General Service Large Nonresidential 201 KW to 999 KW Direct Access Delivery Service
Third Revision of Sheet No.741-1	Schedule 741	Agricultural Pumping Service Direct Access Delivery Service
First Revision of Sheet No. 745-2	Schedule 745	Public DC Fast Charger Optional Transitional Rate Direct Access Delivery Service
Third Revision of Sheet No.747-1	Schedule 747	Large General Service Partial Requirements 1,000 KW and Over Direct Access Delivery Service
Third Revision of Sheet No.747-2	Schedule 747	Large General Service Partial Requirements 1,000 KW and Over Direct Access Delivery Service
Fourth 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.748-2	Schedule 748	Large General Service 1,000 KW and Over Direct Access Delivery Service
Fourth Revision of Sheet No.751-1	Schedule 751	Street Lighting Service Company-Owned System Direct Access Delivery Service
CANCELED Third Revision of Sheet No.752.1	Schedule 752	Street Lighting Service Company-Owned System – No New Service Direct Access Delivery Service

Sheet	**Schedule**	**Title**
CANCELED First Revision of Sheet No.752.2	Schedule 752	Street Lighting Service Company-Owned System – No New Service Direct Access Delivery Service
Fourth Revision of Sheet No.753-1	Schedule 753	Street Lighting Service Consumer-Owned System Direct Access Delivery Service
Fourth Revision of Sheet No.754	Schedule 754	Recreational Field Lighting–Restricted Direct Access Delivery Service
Third Revision of Sheet No.776R-1	Schedule 776R	Large General Service-Partial Requirements Service-Economic Replacement Service Rider Direct Access Delivery Service
First Revision of Sheet No. 848-1	Schedule 848	Large General Service 1,000 KW and Over Direct Access Delivery Service – Distribution Only
First Revision of Sheet No. 848-2	Schedule 848	Large General Service 1,000 KW and Over Direct Access Delivery Service – Distribution Only
Third Revision of Sheet No. R1-3	Rule 1	General Rules and Regulations Definitions
Second Revision of Sheet No. R1-5	Rule 1	General Rules and Regulations Definitions

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:

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

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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, 2020 (Order No. 20-040).

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 374

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, 2021. In this general rate case filing the Company is requesting an increase in rates of approximately $78.0 million, or 6 percent. The Company is also requesting recovery of costs related to the early closure of Cholla Unit 4, resulting in an increase of $17.3 million. Offsetting these increases, is the Company's proposal to amortize deferred tax benefits associated with the Tax Cuts and Jobs Act (TCJA), which reflects a decrease to rates of approximately $24.9 million. The combined effect of these three components is an increase in rates of approximately $70.8 million or 5.4 percent.[1] 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

[1] The net increase of $70.8 million, or 5.4 percent overall on January 1, 2021, consists of the proposed price change including resetting Schedule 299, the Rate Mitigation Adjustment, and the net impact to customers of separate tariff riders for proposed Schedule 195 – Federal Tax Act Adjustment and Schedule 197 – Generation Plant Removal Adjustment.

the prices and terms of PacifiCorp's electric service to its Oregon retail customers. The Company provides electric service to approximately 615,000 retail customers in Oregon and approximately 1.9 million total retail customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp's principal place of business is Portland, Oregon.

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II. CASE SUMMARY

This case is based upon a historical base period of 12 months ended June 2019, with normalizing and pro forma adjustments to calculate a calendar year 2021 future test period with the exception of capital additions, which are based on calendar year-end 2020 balances. The new rates will become effective no later than January 1, 2021, 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 9.3 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 10.2 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. New System Investments

The Company continues to make new investments in the system required to provide safe, adequate, and reliable service to customers and to comply with regulatory mandates. This case includes investments in all facets of the system—including transmission, generation, and distribution—to bolster reliability and improve power delivery. For example, this filing includes the investments related to the new wind and repowering investments in PacifiCorp's Energy Vision 2020 project, PacifiCorp's Pryor Mountain project, and addition of a fish passage at the Company's Lewis River hydroelectric projects. Additional investments to transmission infrastructure, renewable resources, and pollution controls are included in the Company's revenue requirement.

2. Revised Depreciation Rates

The Company's need for this rate increase is driven, in part, by the impact associated with the revised depreciation rates proposed by the Company in docket UM 1968. The

Company filed its application for authority to implement revised depreciation rates on September 13, 2018. As part of that filing, the Company requested authority to implement the revised depreciation rates in its accounting system on January 1, 2021, which coincides with the beginning of the rate effective period in this proceeding. Additionally, PacifiCorp enlisted a third-party study of demolition and decommissioning costs of seven of its coal-fueled resources, to incorporate more accurate estimates of those costs in the depreciation schedules. Concurrent with this filing, PacifiCorp is filing supplemental testimony in docket UM 1968 to update the depreciable lives to be consistent with the 2019 Integrated Resource Plan and the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol) and to include the revised decommissioning costs consistent with the Decommissioning Study filed on January 16, 2020. The updated depreciable lives and the results of the decommissioning study have been incorporated into this general rate case.

3. Wildfire Mitigation Costs

PacifiCorp is adapting to the changes in wildfire risk through adoption of accelerated and enhanced wildfire mitigation measures as part of its wildfire mitigation program and will incur significant incremental capital costs over the next several years. The Company's revenue requirement includes both operations and maintenance and capital costs associated with wildfire-related issues. PacifiCorp is also proposing a mechanism to recover these costs going forward.

4. Coal-Fueled Plants

PacifiCorp is requesting recovery of investments in emissions control equipment installed at Hunter Unit 1, Jim Bridger Units 3-4, Hayden Units 1-2, and Craig Unit 2. PacifiCorp, and the joint owners of these facilities, installed selective catalytic reduction systems (SCR) at these facilities to reduce the emission of sulfur oxides and nitrous oxides, in compliance with applicable requirements. Also included in the revenue requirement are costs associated with the conversion of the Naughton Unit 3 facility from coal to gas, and a proposed treatment of costs associated with the closure of Cholla Unit 4 in 2020.

Additionally, in PacifiCorp's Multi-State Process, PacifiCorp and stakeholders from across its six-state service territory agreed on a new 2020 Protocol. The signatories to the 2020 Protocol agreed to a process for a state commission to approve discontinuing the use of an existing resource and exclusion of costs and benefits of that resource from customer rates through the issuance of an exit order setting an exit date. PacifiCorp is requesting that the Commission approve the requested exit dates identified for PacifiCorp's coal-fueled plants. PacifiCorp is also proposing a mechanism to remove from rates the costs from the coal plants following the exit dates.

5. Pricing Proposals

PacifiCorp is proposing a number of changes to pricing to modernize its tariffs to align with current usage and technology. For example, PacifiCorp is seeking changes to its street lighting programs to incentivize changes to light-emitting diode technology. PacifiCorp is also seeking to flatten its residential tiered rate structure and modify the basic charge for single- and multi-family service. Additionally, PacifiCorp proposes modernizing the time of use periods for its large non-residential customers and increasing the differential between on- and off-peak energy.

6. Annual Power Cost Adjustment

PacifiCorp is proposing a revision to its net power cost (NPC) forecasting process and true-up mechanism due to changing market conditions and additional resource variability.

D. Mitigating Factors

In light of the current economic climate, PacifiCorp is keenly aware of the financial pressures faced by its customers. The Company has therefore taken several steps to mitigate the rate increase request.

The Company has leveraged economies of scale to invest in non-emitting resources while simultaneously providing system savings to customers. Additionally, participation in the Energy Imbalance Market allows PacifiCorp to obtain the lowest-cost energy available in near real-time, facilitating access to zero-fuel-cost energy to benefit the region and Oregon. The Company's concurrently-filed Transition Adjustment Mechanism also reflects the power cost and production tax credit benefits of new renewables added to PacifiCorp's system. These benefits result in a concurrently-effective proposed rate decrease of $49.2 million, resulting in an overall rate increase of (general rate case and TAM combined) $21.6 million or 1.6 percent.

III. TESTIMONY SUMMARY

The Company's direct case consists of the testimony and exhibits of 14 witnesses:

Stefan A. Bird, President and Chief Executive Officer, Pacific Power, provides an overview of PacifiCorp, its Oregon service area, and the strategies the Company is pursuing to provide its customers with low-cost, reliable, and non-emitting generation.

Etta Lockey, Vice President, Regulation, provides an overview of PacifiCorp's current filing and support of the Company's policy positions throughout this filing.

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, implementation of the effects of the TCJA consistent with recent Commission decisions, and the Company's projected pension costs.

Ann E. Bulkley, economist and principal at Concentric Energy Advisors, provides a comparison of PacifiCorp's business and financial risk compared to peer utilities, recommends a cost of equity, and provides supporting analyses.

Michael G. Wilding, Director of Net Power Costs and Regulatory Policy, addresses proposed changes to the Company's Transition Adjustment Mechanism and Power Cost Adjustment Mechanism.

Frank C. Graves, principal with the Brattle Group, testifies regarding the shifting landscape for PacifiCorp which requires reexamination of the ratemaking mechanisms that the Company has used to forecast and recover NPC.

Rick T. Link, Vice President, Resource Planning and Acquisition, provides the economic analysis supporting the Energy Vision 2020 project, including wind repowering and the new wind and transmission projects, the Pryor Mountain project, the retirement of Cholla Unit 4, the conversion of Naughton Unit 3 to gas, and the installation of emission control systems at Jim Bridger Units 3-4. Mr. Link also presents the Company's load forecast.

Chad A. Teply, Senior Vice President of Business Policy and Development, provides an overview of the development, implementation, and costs of the Energy Vision 2020 project and the Pryor Mountain project, conversion of Naughton Unit 3 to gas, and the emission control retrofit projects at certain coal fueled power plants.

Timothy J. Hemstreet, Managing Director of Renewable Energy and Business Development, provides an overview of the Foote Creek I repowering project and the Merwin Fish Collection and Sorting System on the Lewis River.

Richard A. Vail, Vice President of Transmission Services, discusses the transmission additions necessary to complement the wind generation portfolio expansion as part of the Energy Vision 2020 projects, including construction of the 500 kilovolt Aeolus-to-Bridger/Anticline transmission line, and addresses other important system upgrades.

David M. Lucas, Vice President of Transmission and Distribution Operations, discusses wildfire risk and the Company's incremental investments in wildfire mitigation, and supports other projects including the Oregon Advanced Metering Infrastructure Project.

Melissa S. Nottingham, Manager of Customer Advocacy, proposes updates to PacifiCorp's miscellaneous services and fees to reflect prices that are reasonable, fair, and cost-based.

Shelley E. McCoy, 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 2021 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 February 14, 2020.

Matthew McVee
Chief Regulatory Counsel

Carla Scarsella
Senior Attorney

Ajay Kumar
Senior Attorney

PacifiCorp d/b/a Pacific Power

Exhibit A

Exhibit A
Summary of Requested Electric General Rate Increase
Oregon Allocated
Filed February 14, 2020

(A)	Total revenues collected under proposed rates:	$1,045,692,135
(B)	**<u>Base</u>**	
	Revenue change requested:	
	Total:	$77,993,178
	Net of credits from federal agencies:	$77,993,178
	<u>Net</u>[1]	
	Revenue change requested:	
	Total:	$70,816,000
	Net of credits from federal agencies:	$70,816,000
(C)	**<u>Base</u>**	
	Percentage change in revenues requested:	
	Total %:	6.0%
	Net of credits from federal agencies:	6.0%
	<u>Net</u>[1]	
	Percentage change in revenues requested:	
	Total %:	5.4%
	Net of credits from federal agencies:	5.4%
(D)	Test period:	Calendar year 2021
(E)	Requested return on capital:	7.68%
	Requested return on equity:	10.2%
(F)	Rate base proposed in filing:	$4,194,704,290
(G)	Results of operation:	
	Utility operating income, before proposed change:	$263,890,680
	Utility operating income, after proposed change:	$321,999,512

(H) Effect of rate change on each customer class:

	Base Change	Net Change[1]
• Residential:	6.4%	5.0%
• Small General Service (Schedule 23):	10.7%	5.8%
• General Service 31-200 kW (Schedule 28):	2.6%	4.0%
• General Service 201-999 kW (Schedule 30):	4.0%	4.1%
• Large General Service >= 1,000 kW (Schedule 48):	5.8%	8.6%
• Agriculture Pumping Service (Schedule 41):	10.1%	10.0%
• Street lighting:	-1.7%	-18.9%
• Total	6.0%	5.4%

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

[1] Net Change reflects the net impact to customers on January 1, 2021, of the proposed price change including resetting Schedule 299, the Rate Mitigation Adjustment. It also includes the net impact to customers of separate tariff riders for proposed Schedule 195 – Federal Tax Act Adjustment and Schedule 197 – Generation Plant Removal Adjustment. Including these adjustments, a net increase of $70.8 million, or 5.4 percent overall, is proposed to take effect on January 1, 2021.

ACRONYMS AND ABBREVIATIONS

Acronym/Abbreviation	Term
2013 Rate Case	Docket UE 263
2014 TAM	2014 Transition Adjustment Mechanism, docket UE 264
2017R RFP	2017 Request for Proposals for renewable resources
2020 Protocol	PacifiCorp 2020 Inter-Jurisdictional Allocation Protocol
2021 TAM	2021 Transition Adjustment Mechanism, docket UE 375
230 kV Network Upgrades	Aeolus to Bridger/Anticline 500 kV Line Project and the interconnection of the Energy Vision 2020 Wind Projects
A&G	administrative and general
AAC	all-aluminum conductor
ACS	Accounting Standards Codification
ACSR	aluminum conductor steel-reinforced
ADIT	accumulated deferred income taxes
AFUDC	allowance for funds used during construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
AMT	alternative minimum tax
aMW	average megawatt
APCA	Annual Power Cost Adjustment
APS	Arizona Public Service
ARAM	Average Rate Assumption Method
ATRR	annual transmission revenue requirement
Avista	Avista Corp
B&V	Black & Veatch
BAA	Balancing Authority Area
BART	Best Available Retrofit Technology
Base Period	historical period of the 12 months ended June 2019
BCC	Bridger Coal Company
BES	Bulk Electric System
BHE	Berkshire Hathaway Energy Company
BHER	Berkshire Hathaway Energy Renewables
BLM	Bureau of Land Management
bp	basis point
BPA	Bonneville Power Administration
BTA	build-transfer agreement
Btu	British thermal unit
CAISO	California Independent System Operator
California Commission	California Public Utilities Commission
CAPM	Capital Asset Pricing Model
CCR	coal combustion residuals
CDD	cooling degree day
CELA	Chandar Energy Land Associates, Inc.

Acronym/Abbreviation	Term
CO_2	carbon dioxide
Commission	Public Utility Commission of Oregon
Concentric	Concentric Energy Advisors, Inc.
CPCN	certificate of public convenience and necessity
CPI	Consumer Price Index
CUSIP	Committee on Uniform Securities Identification Procedures
CWIP	capital work in progress
DA/RT	day-ahead versus real-time
DC	direct current
DCF	discounted cash flow
DER	distributed energy resource
DSM	demand-side management
ECAM	Energy Cost Adjustment Mechanism
ECAPM	Empirical Capital Asset Pricing Model
ECD	embedded cost differential
EDAM	Extended Day-Ahead Market
EDIT	excess deferred income tax
EIA	U.S. Energy Information Administration
EIM	Energy Imbalance Market
Energy Vision 2020 Wind Project	TB Flats I and II, Cedar Springs, and Ekola Flats
EPA	U.S. Environmental Protection Agency
EPC	engineer, procure, and construct
EPS	earnings per share
ESR	Electric Service Requirements Manual
ETSR	Energy Transfer System Resource
EWEB	Eugene Water & Electric Board
FERC	U.S. Federal Energy Regulatory Commission
FFO	Funds From Operations
FGD	flue gas desulfurization
FHCA	Fire High Consequence Areas
FIP	Federal Implementation Plan
Fitch	FitchRatings
FNTP	full notice to proceed
FOMC	Federal Open Market Committee
FPI	Facility Point Inspection
Functionalized Oregon Results of Operations Report	PacifiCorp's December 2021 Functionalized Oregon Results of Operations Report
GDP	gross domestic product
GE	General Electric International, Inc.
Global Insight	IHS Global Insight
GRC	general rate case
GRID	Generation and Regulation Initiative Decision Tools

Acronym/Abbreviation	Term
GW	gigawatt
GWh	gigawatt-hour
HDD	heating degree day
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Idaho Commission	Idaho Public Utilities Commission
Idaho Power	Idaho Power Company
IE	independent evaluator
IOUs	investor owned utilities
IRC	Internal Revenue Code
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ISO	independent system operator
KHSA	Klamath Hydroelectric Settlement Agreement
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LAP	load aggregated point
LED	light-emitting diode
Lewis River Projects	Merwin, Yale, and Swift No. 1 hydroelectric projects located in SW Washington
LIBOR	London Inter Bank Offer Rate
LMP	locational marginal price
LNB	low NO_X burner
LNTP	limited notice to proceed
LOLP	loss of load probability
LVSN	low voltage secondary network
Maine PUC	Maine Public Utilities Commission
Marginal Cost Study	PacifiCorp’s State of Oregon December 2021 Marginal Cost Study
MATS	Mercury and Air Toxics Standards
Michigan PSC	Michigan Public Service Commission
MISO	Midcontinent Independent System Operator
Missouri PSC	Missouri Public Service Commission
MMBtu	million British thermal units
MVAr	mega volt amps (reactive)
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NextEra PPA	transmission tie-line between the Cedar Springs II and the Cedar Springs I

Acronym/Abbreviation	Term
NJ Board	New Jersey Board of Public Utilities
Non T&D	non-transmission and distribution
Notice	IRS Notice 2016-31
NO_X	nitrogen oxide
NPC	net power costs
NPM	Nodal Pricing Model
NTTG	Northern Tier Transmission Group
O&M	operation and maintenance
OASIS	Open Access Same-time Information System
OATT	open access transmission tariff
OFPC	Official Forward Price Curve
OREA	Oregon Renewable Energy Act
P/E	Price-to-Earnings Ratio
PACE	PacifiCorp Balancing Authority Area East
PACW	PacifiCorp Balancing Authority Area West
PaR model	Planning and Risk model
PATH Act	Protecting Americans from Tax Hikes Act of 2015
PCAM	Power Cost Adjustment Mechanism
PCRB	Pollution Control Revenue Bond
PEG	price/earnings to growth
PGE	Portland General Electric Company
PHFU	plant held for future use
PM	particulate matter
PNM	Public Service Company of New Mexico
Portland General Electric	Portland General Electric Company
PPA	power purchase agreement
PPUC	Pennsylvania Utility Commission
PSCo	Public Service Company of Colorado
PTC	federal production tax credit
PVRR	present-value revenue requirement
PVRR(d)	present-value revenue requirement differential
Q1	first quarter
QF	qualifying facility
RAC	Renewable Adjustment Clause
RBM	regional business manager
REC	renewable energy certificate
Report	Oregon results of operations report
RFP	request for proposal
RMA	Rate Mitigation Adjustment
ROE	return on equity
ROR	rate of return
RP	risk premium

Acronym/Abbreviation	Term
RPS	renewable portfolio standard
RRA	Regulatory Research Associates
RSGM	Reverse South Georgia Method
RTO	regional-transmission organization
RVOS	Resource Value of Solar
S&P	Standard & Poor's
SB	Senate Bill
SB 1547	Oregon Senate Bill 1547, the Clean Electricity and Coal Transition Plan
SCR	selective catalytic reduction
SEC	Securities and Exchange Commission
SERP	Supplemental Executive Retirement Plan
Settlement Agreement	2004 Lewis River Settlement Agreement
SF 159	Wyoming Senate File 159
SIFMA	Securities Industry and Financial Markets Association
SIP	State Implementation Plan
SNL	Standard & Poor's Global Market Intelligence
SO model	System Optimizer model
SO_2	sulfur dioxide
STATCOM	Static Synchronous Compensator
STEAM	science, technology, engineering, the arts and mathematics
T&D deferral credits	transmission and distribution deferral credits used for demand-side management modeling
TAM	Transition Adjustment Mechanism
TCJA	Tax Cuts and Jobs Act
Test Period	forecast period of the 12 months ending December 31, 2021
TPL Standards	transmission planning standards
Tri-State	Tri-State Generation and Transmission Association, Inc.
U.S.	United States
UAMPS	Utah Associated Municipal Power Systems
Utah Commission	Utah Public Service Commission
UWUA	Utility Workers Union of America
Vestas	Vestas American Wind Technology, Inc.
Vitesse	Vitesse, LLC
VRDB	Committee on Uniform Securities Identification Procedures
Washington Commission	Washington Utilities and Transportation Commission
WDEQ	Wyoming Department of Environmental Quality
WECC	Western Electricity Coordinating Council
WROE	weighted return on equity
WTG	wind-turbine-generator
Wyoming Commission	Wyoming Public Service Commission

CERTIFICATE OF SERVICE

I certify that I served 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 374

OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 dockets@oregoncub.org	MICHAEL GOETZ **(C)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND, OR 97205 mike@oregoncub.org
ROBERT JENKS **(C)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 bob@oregoncub.org	
PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	AJAY KUMAR PACIFICORP 825 NE MULTNOMAH PORTLAND, OR 97232 ajay.kumar@pacificorp.com
STAFF	
SOMMER MOSER **(C)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 sommer.moser@doj.state.or.us	MARIANNE GARDNER **(C)** PUBLIC UTILITY COMMISSION PO BOX 1088 SALEM, OR 97308 marianne.gardner@state.or.us
ELIZABETH B. UZELAC **(C)** PUC STAFF - DEPARTMENT OF JUSTICE BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM, OR 97301 elizabeth.b.uzelac@state.or.us	

Dated February 14, 2020.

Mary Penfield
Adviser, Regulatory Operations

Docket No. UE 374
Exhibit PAC/100
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Stefan A. Bird

February 2020

TABLE OF CONTENTS

ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp.

A. My name is Stefan A. Bird, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as President and Chief Executive Officer of Pacific Power. I am testifying for PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

Q. Please describe your education and professional experience.

A. I hold a Bachelor of Science in mechanical engineering from Kansas State University. I joined PacifiCorp in January 2007, where I held the position of Senior Vice President of commercial and trading[1] until I assumed my current position in March 2015. From 2003 to 2006, I served as president of CalEnergy Generation U.S., a developer, owner, and operator of qualifying facilities (QF) and merchant generation assets. From 1999 to 2003, I was vice president of acquisitions and development for Berkshire Hathaway Energy, formerly known as MidAmerican Energy Holdings Company. From 1989 to 1997, I held various positions at Koch Industries, Inc., including energy marketing, financial services, corporate acquisitions, project engineering, and maintenance planning in the Americas and Europe.

II. PURPOSE OF TESTIMONY

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

A. My testimony provides an overview of PacifiCorp, its Oregon service area, and the strategies the Company is pursuing to provide its Oregon customers with low-cost,

[1] In this capacity, I oversaw PacifiCorp's system dispatch and balancing operations, wholesale power and natural gas risk management, regulatory net power cost recovery, load forecasting, integrated resource planning and resource acquisitions.

reliable, and non-emitting generation to power their homes, businesses, and communities. I also explain the progress PacifiCorp has made since its last full general rate case, docket UE-263 (2013 Rate Case),[2] to deliver these essential customer benefits. Finally, I introduce the Company witnesses that provide direct testimony in support of PacifiCorp's rate request.

III. DESCRIPTION OF PACIFICORP AND OREGON SERVICE AREA

Q. Please provide a brief description of PacifiCorp.

A. As an investor-owned, multi-jurisdictional electric utility, PacifiCorp serves nearly two million customers in six western states: California, Idaho, Oregon, Utah, Washington, and Wyoming. The Company serves its customers with a vast, integrated system of generation and transmission that spans 10 states and connects customers and communities across the West. PacifiCorp's integrated system provides benefits to customers in all six states and includes generation, transmission, and distribution assets. PacifiCorp owns, or has interests in thermal, hydroelectric, wind-powered, solar, and geothermal generating facilities, with a net-owned capacity of 10,894 megawatts (MW). PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions, and other market participants to balance and optimize the economic benefits of electricity generation, retail customer loads, and existing wholesale transactions.

PacifiCorp provides wholesale transmission service under its open access transmission tariff approved by the Federal Energy Regulatory Commission and owns or has interests in approximately 16,500 miles of transmission lines. PacifiCorp

[2] *In the matter of PacifiCorp, dba Pac. Power,* Docket No. UE 263, Order No. 13-474 (Dec. 18, 2013).

operates two Balancing Authority Areas (BAAs)—PacifiCorp Balancing Authority Area East (PACE) and PacifiCorp Balancing Authority Area West (PACW) that together comprise the largest privately owned and operated grid in the Western United States.

Q. What are the advantages of PacifiCorp's large regional footprint?

A. PacifiCorp's integrated system allows PacifiCorp to deliver low-cost generation from some of the best renewable generation sites in the country to PacifiCorp's customers, reducing power costs and emissions for customers, and supporting local economies and communities throughout the West. As PacifiCorp looks toward the future, there are even more opportunities for customers to benefit from the connected west that PacifiCorp's integrated system creates. These opportunities may come from participation in a regional resource adequacy program or expansion of markets that allow participants to more efficiently operate their systems. PacifiCorp is and will remain actively engaged in finding additional ways to leverage our vast, integrated system for the benefit of our customers.

Q. Please describe PacifiCorp's Oregon service area.

A. In Oregon, PacifiCorp serves approximately 615,000 customers. Maps of the Company's service territory are provided in Exhibit PAC/101. The Company's Oregon service area is comprised of urban and rural areas. PacifiCorp's sales and revenues are distributed among residential customers, small businesses, and large businesses served under retail tariffs subject to the jurisdiction of the Public Utility Commission of Oregon (Commission). Table 1 below provides the June 2019 number of retail customers and usage for each of the major customer classes that account for the majority of the Company's customer base.

Table 1: Number of Customers and Usage in PacifiCorp's Oregon Service Area

Class	Number of Customers	Usage (megawatt-hours)
Residential	527,003	5,615,069
Commercial	77,267	5,373,138
Industrial	1,775	1,617,437
Irrigation	7,984	351,867
Lighting	1,447	38,375
Total	615,477	12,995,886

Q. What are some of the ways PacifiCorp engages with its communities and customers within its Oregon service area?

A. PacifiCorp is a proud member of its Oregon communities. Over the last several years, the Company deepened its connection to its communities in a variety of ways.

The Company has sponsored a number of community events that focused on the fields of science, technology, engineering, the arts, and mathematics (STEAM). Invent 2018 and Invent 2019, which were held in Grants Pass in October 2018 and October 2019, were interactive community event that showcased local innovation and STEAM. Invent was designed as an interactive events for individuals and families with activities that included drone flying, virtual reality, graphic design, designing and testing wind turbine blades, cooking with solar ovens, art stations, woodworking, and screen printing. Educational opportunities available at the event included an introduction to the Rogue Community College Innovation Hub, a STEAM focused education space; energy education; and information about existing community programs. The Company will also be involved in Invent 2020.

PacifiCorp is also sponsoring the Columbia River Maritime Museum Miniboat Program, which is a global, multidisciplinary STEAM learning experience for 5th, 6th, and 7th graders in Oregon and Southwest Washington and Japan. In the program, students cooperatively design, build, launch, and track seaworthy, GPS-equipped, solar-powered miniboats on a journey across the Pacific Ocean. In addition to financial participation, PacifiCorp has provided mentors from engineering, public relations, and renewable energy operations. The Company is also aiding in publicizing the program to gain additional sponsors in years to come.

PacifiCorp is also engaged in transportation electrification efforts within the state. Recognizing that the electric transportation market is in an emerging market that represents an opportunity for improved air quality, reduced greenhouse gas emissions, and financial benefits for drivers, including low- and moderate-income populations, PacifiCorp is investing over $26 million across its system to support electric vehicle fast chargers along key corridors, including in Oregon. In Oregon that includes $7.6 million approved for current programs through 2020, including over $1 million in awarded grants for charging infrastructure. The first PacifiCorp-operated fast chargers opened in December 2019 in Madras with four more locations anticipated by the end of 2020.

For the ever-increasing engagement with customers who interact with us on our digital platform, the Company overhauled its website to make customer transactions faster, easier, and more secure. To increase customer awareness during service interruptions, PacifiCorp improved its outage map and outage status communications through multiple channels.

These are just some of the recent examples of PacifiCorp's engagement with its Oregon customers and communities.

Q. Please describe PacifiCorp's core principle with respect to providing service to customers.

A. PacifiCorp's core principle is to provide sustainable energy solutions in the form of safe, reliable, and affordable energy to customers in Oregon and throughout the West. The Company has upheld this ideal for close to 110 years and remains steadfast in this commitment even as the electricity sector transforms through public policies, emerging and maturing technologies, and the rise of a regional energy market. The Company is meeting the new demands of this transformation without losing focus on its commitment to delivering safe, reliable, and affordable energy.

PacifiCorp is at a pivotal moment as our system adapts to changing market conditions for generating resources and increasing demand from customers for energy from specific types of generating resources. PacifiCorp is uniquely positioned to respond to these changes as the result of our vast energy system and geographically diverse generation footprint, which is facilitated by our expansive transmission system.

IV. COMPANY INVESTMENTS SINCE THE 2013 RATE CASE

Q. Please describe PacifiCorp's continuous adaptation to the changing energy landscape while keeping electricity affordable.

A. Since the 2013 Rate Case, PacifiCorp has taken many steps to meet the challenges of the changing energy landscape while keeping electricity affordable. These steps include investing in cost-effective sustainable energy solutions to facilitate a transition on PacifiCorp's system including deploying market solutions and technologies that empower our customers and improve service, development of Energy Vision 2020, and pursuing the 2019 Integrated Resource Plan (IRP) action plan.

For example, the Company partnered with the California Independent System Operator (CAISO) to create the Energy Imbalance Market (EIM) and has supported the successful expansion of the EIM across the West. PacifiCorp is currently working with stakeholders to explore the potential for an Extended Day-Ahead Market (EDAM) to further increase customer savings and maximize use of non-emitting resources.

PacifiCorp has taken advantage of the declining cost of renewable energy resources and the availability of federal production tax credits (PTCs) to invest in new renewable resources and transmission in the West including its Energy Vision 2020 projects, which are nearing completion.

Also, to enable its customers to make informed decisions about their energy service, PacifiCorp deployed the Oregon Advanced Metering Infrastructure (AMI)

Project, which provides a number of customer benefits, such as lowering costs and improving reliability while empowering customers to better manage their energy use.

Q. Please explain the EIM and EDAM.

A. The EIM is a real-time bulk power trading market, which uses advanced market systems to automatically find and deliver the lowest-cost energy to serve customer demand on a real-time basis across a wide geographic area. Utilities voluntarily participating in the EIM maintain control over their assets and remain responsible for balancing requirements while sharing in the benefits the market produces. Additional benefits of the EIM include improved situational awareness for increased reliability and more effective integration of renewables and utilization of the transmission system.

Since the CAISO and PacifiCorp, the first participants, launched the market in November 2014, the EIM has produced benefits of $861.8 million, as of December 31, 2019.[3] PacifiCorp customers' share of the EIM benefits are an estimated $235.3 million.[4] In addition to monetary benefits, participation in the EIM has enabled PacifiCorp to operate its thermal generation fleet to more closely follow variable-energy resources such as wind and solar. As a result of this change in operation, in 2016 there was a step-change reduction in PacifiCorp's carbon dioxide (CO_2) emissions of approximately five million tons as compared to the 2011 to 2015 annual average emissions. This step-change reduction has been maintained through 2019—equaling an approximate reduction in CO_2 emissions of 20 million tons over

[3] *See* BENEFITS, WESTERN ENERGY IMBALANCE MARKET, https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx (last visited Feb. 1, 2020).
[4] *Id.*

four years of EIM operation. Since its inception, nine utilities have joined the EIM, and 11 more have committed to join by 2022. Together, this represents over 70 percent of the West's total electricity demand. PacifiCorp customers and customers of other market participants have benefited as market participation has grown.

More recently, the CAISO launched a stakeholder process to explore the expansion of the EIM to a day-ahead framework, the EDAM. The EDAM initiative is looking to develop an approach to extend participation in a day-ahead market to the EIM entities in a framework similar to the existing EIM approach for the real-time market, rather than requiring full integration into the CAISO BAA. The EDAM is expected to improve market efficiency by integrating renewable resources using day-ahead unit commitment and scheduling across a larger area. With an appropriate market design, PacifiCorp expects that expansion of the EIM to the EDAM will be a critical component to cost-effectively de-carbonize PacifiCorp's system and integrate its aggressive renewable portfolio strategy set forth in the 2019 IRP.

Q. Please explain how the Company is investing in a cleaner energy future.

A. PacifiCorp's Energy Vision 2020 projects increase PacifiCorp's non-emitting generation portfolio with new and repowered wind generation resources and new transmission, while leveraging federal PTCs to provide savings to customers over the life of the projects. These investments support an energy future that decreases greenhouse gas emissions, while providing benefits to customers over the lives of the resources. Please see the direct testimony of Mr. Rick T. Link for further discussion of customer benefits associated with Energy Vision 2020.

Energy Vision 2020 consists of two major components: (1) wind repowering; and (2) investments in new wind and transmission. These new projects deliver more wind generation to PacifiCorp's system along with long-term savings for customers. Please see the direct testimony of Mr. Chad A. Teply, Mr. Timothy J. Hemstreet, and Mr. Richard A. Vail, who address the new wind generation projects, wind repowering, and transmission projects, respectively, associated with Energy Vision 2020.[5]

Q. Will the 2019 IRP further increase the Company's energy diversity in the Western United States?

A. Yes. In the 2019 IRP, PacifiCorp's preferred portfolio indicates a need to further expand its portfolio with new low-cost wind generation, solar generation, storage, and demand-side resources to meet changing customer needs. PacifiCorp's 2019 IRP provides the roadmap by which the Company will reduce greenhouse gas emissions over the next 20 years. As reflected in the 2019 IRP, the Company will be acquiring nearly 14,000 MW of new non-emitting generation and storage by 2038. Further, by 2030, PacifiCorp will have reduced greenhouse gas emissions system-wide by nearly 60 percent from 2005 levels. Figure 1 shows the Emission Reductions, Wind and Solar Capacity, and Energy Cost Savings associated with the 2019 IRP preferred portfolio.

PacifiCorp's 2019 IRP supports the Company's broader three-point strategy (noted below). This strategy recognizes three key, inter-related focus areas that must

[5] All of the Company's repowering projects have been addressed in proceedings before the Commission, with the exception of Foote Creek I, which is addressed in the direct testimony by Mr. Hemstreet in this general rate case. *See In the matter of PacifiCorp, dba Pac. Power, 2019 Renewable Adjustment Clause*, Docket No. UE 352, Order 19-304, pp. 8-9. *See also In the matter of PacifiCorp, dba Pac. Power, 2020 Renewable Adjustment Clause*, Docket No. UE 369, Stipulation and supporting Joint Testimony filed on January 31, 2020. The Commission has not yet ruled on the Stipulation entered into by the parties in Docket No. UE 369.

work in concert to de-carbonize the West, while simultaneously meeting the essential requirements of being a low-cost, reliable and safe energy provider.

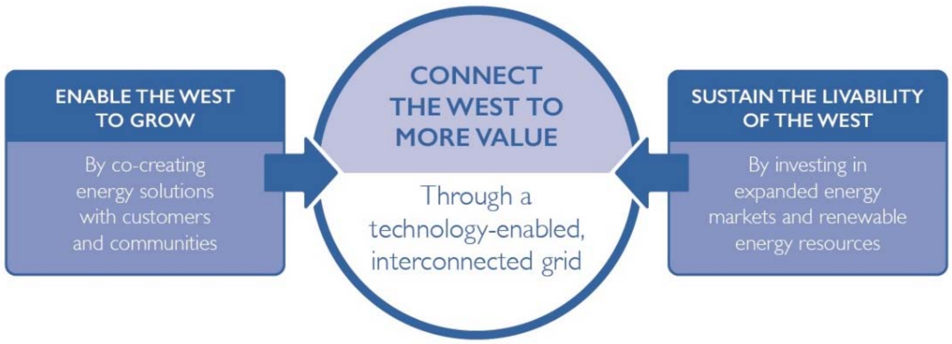
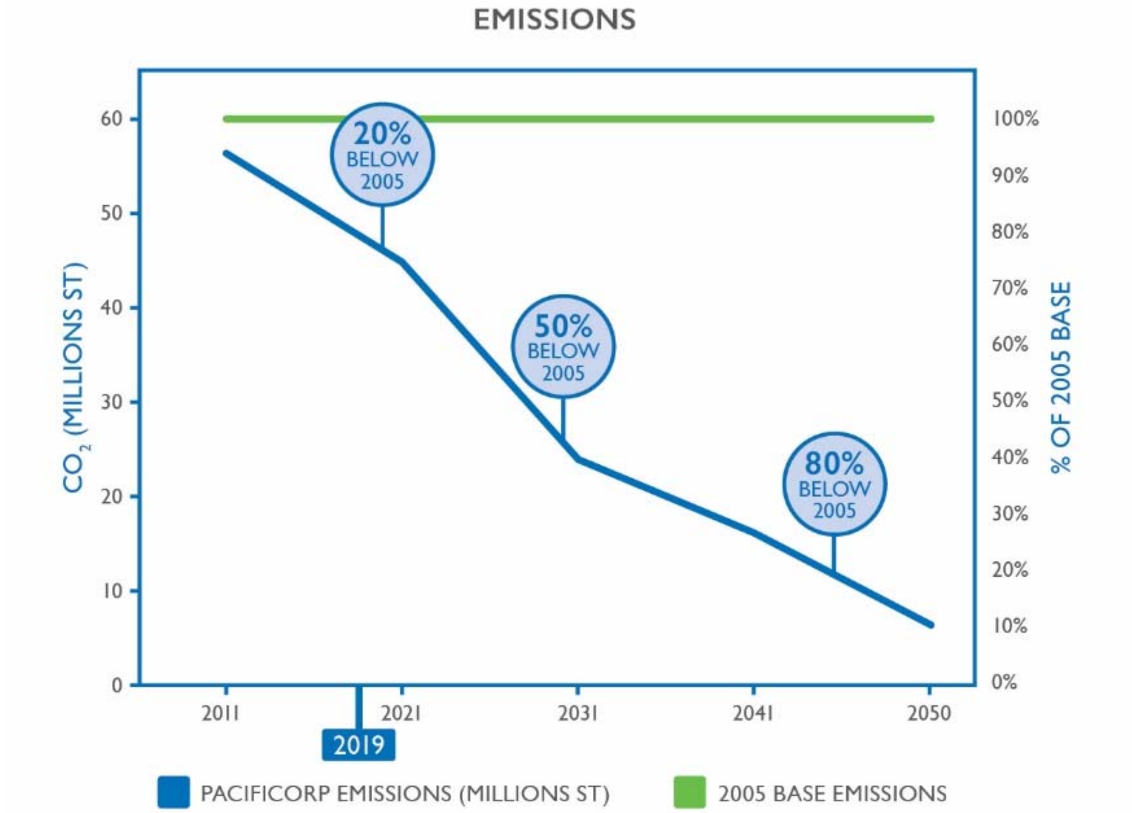
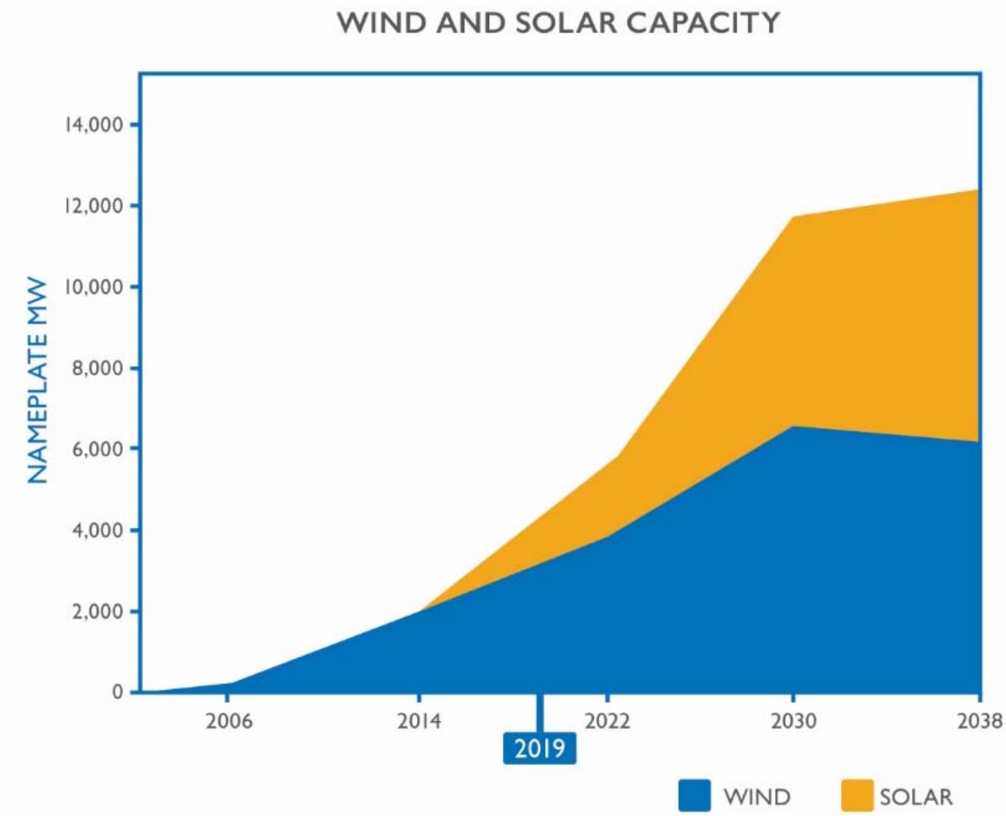
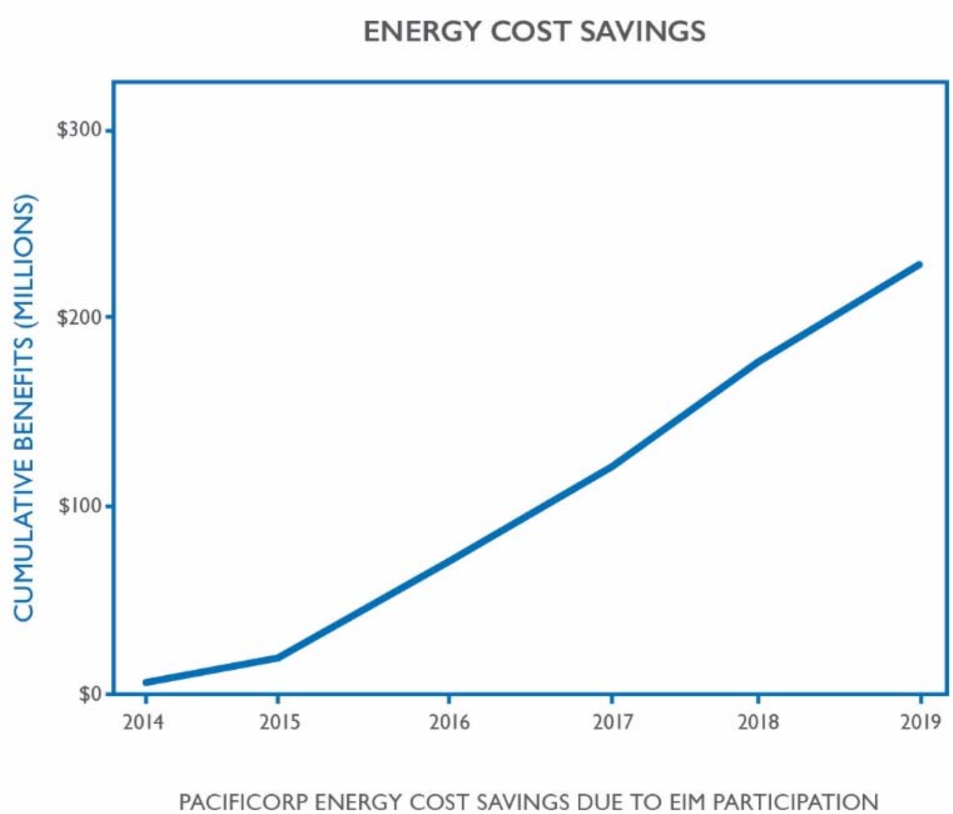


Figure 1: Emission Reductions, Wind and Solar Capacity, and Energy Cost Savings[6]



[6] Source: PacifiCorp 2019 IRP filed on October 18, 2019, in Docket No. LC 70. I note that the Energy Cost Savings Chart reflects EIM benefits at the time of the 2019 IRP. The EIM benefits that I discuss are the total benefits updated as of December 31, 2019.


WIND AND SOLAR CAPACITY
NAMEPLATE MW
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
2006
2014
2019
2022
2030
2038
WIND
SOLAR


ENERGY COST SAVINGS
CUMULATIVE BENEFITS (MILLIONS)
$300
$200
$100
$0
2014
2015
2016
2017
2018
2019
PACIFICORP ENERGY COST SAVINGS DUE TO EIM PARTICIPATION

Q. Has the Company recently taken additional steps to reduce greenhouse gas emissions on its system?

A. Yes. As the Company moves toward increasing reliance on new non-emitting generation, PacifiCorp is continuing to evaluate the economics of the early retirement of its existing coal-fueled power plants. On December 27, 2019, the Company announced it would retire Cholla Unit 4 by December 31, 2020. The Cholla power plant consists of four units located near Joseph City, Arizona, with a combined generating capability of 995 MW. PacifiCorp owns approximately 37 percent of the plant's common facilities and 100 percent of Unit 4 which was commissioned in 1981 with a generating capability of 395 MW.

The Company's 2017 IRP[7] and 2019 IRP[8] both identified the retirement of Cholla Unit 4 as early as 2020. Based on an economic analysis conducted following the 2019 IRP, which is discussed in the direct testimony of Mr. Link, PacifiCorp initiated the process of retiring Unit 4 and anticipates being able to achieve retirement by year-end 2020. The early retirement of Cholla Unit 4 is not only in line with reducing greenhouse gas emissions system-wide, but also the Oregon law that eliminates coal from PacifiCorp's rates by 2030.[9]

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[7] PacifiCorp, 2017 IRP (Apr. 4, 2017), vol. I, p. 7, 20; PacifiCorp, 2017 IRP Update (May 1, 2018), p. 12 (Docket No. LC 67).
[8] PacifiCorp, 2019 IRP (Oct. 18, 2019), vol. I, p. 98 (Docket No. LC 70).
[9] See Section 1(2) of Senate Bill 1547, effective date Mar. 8, 2016. See https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled.

Q. Please describe how PacifiCorp's investment in these initiatives benefits customers in Oregon.

A. PacifiCorp is uniquely situated to leverage economies of scale to invest in non-emitting resources while simultaneously providing system savings to customers. Participation in the EIM allows PacifiCorp to obtain the lowest-cost energy available in near real-time, facilitating access to zero-fuel-cost energy to benefit the region and Oregon. If there is excess solar energy in California, excess wind in Wyoming, or excess hydropower in the Pacific Northwest, the Company can transport that low-cost energy across the grid and displace higher cost resources.

PacifiCorp's Energy Vision 2020 projects represent an investment not just in decarbonizing PacifiCorp's generation portfolio and increasing the Company's renewable capacity, but also in directly benefiting communities across the West. The Energy Vision 2020 projects have created hundreds of construction jobs, and have added millions of dollars in construction tax revenue and ongoing annual state and local tax revenue in Oregon, Washington, and Wyoming. In the past 13 years, PacifiCorp has become the largest regulated owner of wind generation in the West. From 2018 to 2020, the Company will have increased the percentage of non-emitting resources in our portfolio by 70 percent.

Q. Since the 2013 Rate Case, in addition to sustainable energy solutions described above, has PacifiCorp deployed technologies that empower its customers and improves service?

A. Yes. PacifiCorp's core principle is to provide sustainable energy solutions in the form of safe, reliable, affordable, and increasingly clean energy to customers. The

Company has and continues to take steps to provide sustainable energy solutions in the form of investments as I have explained above. In addition, PacifiCorp has deployed the Oregon AMI Project, which provides a number of benefits including empowering customers to reduce and manage their energy costs.

Q. Please describe the Oregon AMI Project.

A. Completed in 2019, the Company's Oregon AMI Project is comprised of four parts: the installation of over 600,000 AMI meters; the installation of a field area network; the development, installation, and configuration of information technology software; and the development of an energy usage website. The Oregon AMI Project offers a wide range of customer benefits. The Company's operating costs decrease through the reduction or elimination of costs related to meter reading, which directly impact customer rates. Because the Company has greater visibility of its system, the Company is able to react faster to outage information. Armed with hourly energy consumption, customers can make informed decisions about their energy usage. With this granular data, the Oregon AMI Project investment can facilitate residential demand response programs to support the bulk power system. For more details about the Oregon AMI Project and expected benefits, see the direct testimony of Company witness Mr. David M. Lucas.

V. INTRODUCTION OF COMPANY WITNESSES

Q. How is PacifiCorp presenting this case?

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

- In Exhibit PAC/200, Etta Lockey, Vice President of Regulation, will describe PacifiCorp's request in this proceeding and summarize the regulatory policy of the Company.

- In Exhibit PAC/300, Nikki L. Kobliha, PacifiCorp's Chief Financial Officer, will provide the Company's overall cost of capital recommendation for the Company, including a capital structure to maximize value and minimize risk. Ms. Kobliha also describes PacifiCorp's implementation of the effects of the Tax Cuts and Jobs Act consistent with recent Commission decisions. Finally, she supports the Company's projected pension costs.

- In Exhibit PAC/400, Ann E. Bulkley, economist and principal at Concentric Energy Advisors, provides a comparison of PacifiCorp's business and financial risk compared to peer utilities, recommends a cost of equity, and provides supporting analyses.

- In Exhibit PAC/500, Michael G. Wilding, the Company's Director of Net Power Costs and Regulatory Policy, addresses proposed changes to the Company's Transition Adjustment Mechanism and Power Cost Adjustment Mechanism.

- In Exhibit PAC/600, Frank C. Graves, principal with the Brattle Group, also testifies regarding the shifting landscape for PacifiCorp which requires reexamination of the ratemaking mechanisms that the Company has used to forecast and recover net power cost.

- In Exhibit PAC/700, Rick T. Link, PacifiCorp's Vice President of Resource Planning and Acquisition, provides the economic analysis supporting the Energy Vision 2020 projects, including wind repowering and the new wind and transmission projects. Mr. Link also provides the economic analyses of the Pryor Mountain Wind Project, the retirement of Cholla Unit 4, the conversion of Naughton Unit 3, and the installation of selective catalytic reduction emission control systems at Jim Bridger Units 3 and 4. Finally, he presents the Company's load forecast.

- In Exhibit PAC/800, Chad A. Teply, PacifiCorp's Senior Vice President of Business Policy and Development, provides an overview of the development, implementation, and costs of the Energy Vision 2020 Wind Projects and the Pryor Mountain Wind Project. Mr. Teply supports the costs to complete the emission control retrofit projects at certain coal fueled power plants. Finally, he discusses the conversion to gas at Naughton Unit 3.

- In Exhibit PAC/900, Timothy J. Hemstreet, the Company's Managing Director of Renewable Energy and Business Development, provides an overview of the Foote Creek I repowering project and the Merwin Fish Collection and Sorting System on the Lewis River.

- In Exhibit PAC/1000, Richard A. Vail, PacifiCorp's Vice President of Transmission Services, discusses the transmission additions necessary to complement the wind generation portfolio expansion as part of the Energy Vision 2020 projects, including construction of the 500 kilovolt Aeolus-to-Bridger/Anticline transmission line, and addresses other important system upgrades.

- In Exhibit PAC/1100, David M. Lucas, the Company's Vice President of Transmission and Distribution Operations, discusses wildfire risk and the Company's wildfire mitigation efforts in Oregon. He also supports other projects including the Oregon AMI Project.

- In Exhibit PAC/1200, Melissa S. Nottingham, Manager of Customer Advocacy, proposes updates to PacifiCorp's miscellaneous services and fees to reflect prices that are reasonable, fair, and cost-based.

- In Exhibit PAC/1300, Shelley E. McCoy, PacifiCorp's Revenue Requirement Manager, summarizes the overall test year revenue requirement, pro forma adjustments, and the rate base calculation methodology.

- In Exhibit PAC/1400, 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 2021 revenue requirement to achieve fair, just, and reasonable prices for customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Docket No. UE 374
Exhibit PAC/101
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

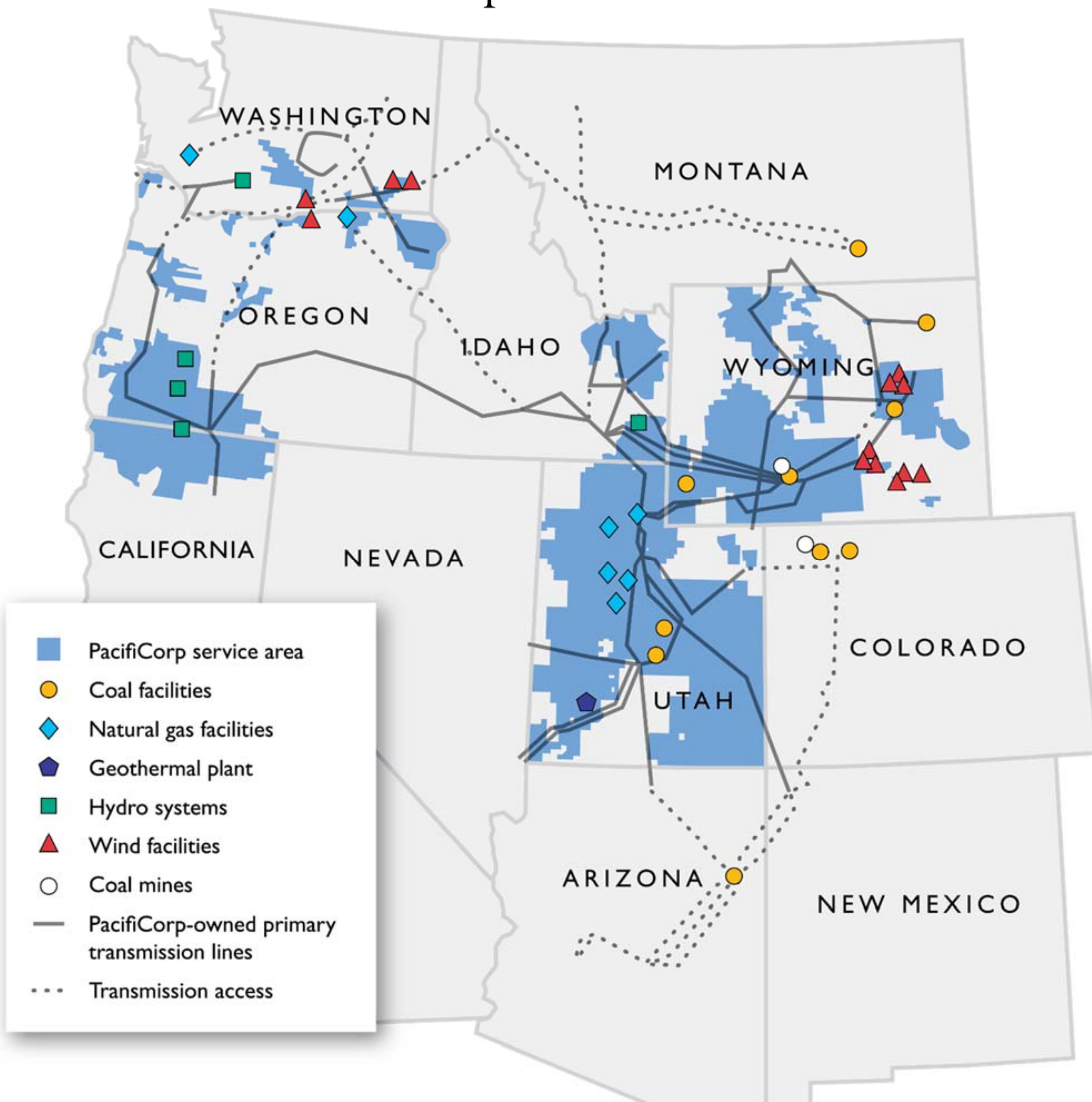
Exhibit Accompanying Direct Testimony of Stefan A. Bird

Maps of PacifiCorp's Service Territory

February 2020

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

PacifiCorp Service Areas



Pacific Power Oregon Service Area

Docket No. UE 374
Exhibit PAC/200
Witness: Etta Lockey

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Etta Lockey

February 2020

TABLE OF CONTENTS

ATTACHED EXHIBIT

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp.

A. My name is Etta Lockey and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Vice President, Regulation. I am testifying for PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

Q. Please describe your education and professional experience.

A. I have a Bachelor of Arts degree in Political Science from the University of Oregon and a Juris Doctorate from the Northwestern School of Law of Lewis and Clark College. I started at PacifiCorp as an attorney in 2013 and assumed my current role as Vice President, Regulation in 2017.

Q. Have you testified in other regulatory proceedings?

A. Yes. I have sponsored testimony on behalf of PacifiCorp in California, Oregon, and Washington.

II. PURPOSE OF TESTIMONY

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

A. I provide an overview of PacifiCorp's current filing and support the Company's policy positions throughout this filing. Among other things, I give context for this rate filing, which comes at a pivotal time for PacifiCorp. The Company is responding proactively to rapidly changing market conditions, including through implementation of our Energy Vision 2020 plan and implementation of the 2019 Integrated Resource Plan (IRP) action plan, which embodies our commitment to a future that benefits our customers, our communities, and the environment with low-cost renewable generating resources.

The overall impact to customer rates as a result of this general rate case filing and the Company's Transition Adjustment Mechanism (TAM) filing is an increase of $21.6 million, or an average rate increase of 1.6 percent, which consists of four main components. First, in this general rate case filing, the Company is requesting an increase in rates of approximately $78.0 million, or 6 percent. Second, the Company is requesting recovery of costs related to the early closure of Cholla Unit 4, resulting in an increase of $17.3 million. Third, offsetting these increases is the Company's proposal, set forth in the testimony of Ms. Shelley E. McCoy, to amortize deferred tax benefits associated with the Tax Cuts and Jobs Act (TCJA), which reflects a decrease to rates of approximately $24.9 million. Finally, offsetting the rate increase in this general rate case is a $49.2 million decrease in rates proposed in the concurrently filed TAM; the rate effective date in the case and the in the TAM are both January 1, 2021.

The modest request in this case demonstrates PacifiCorp's prudent and efficient management of its costs that has allowed the Company to stay out of general rate cases beyond its commitment made in its last general rate case, docket UE 263 (2013 Rate Case),[1] all while adhering to the core principle of providing sustainable energy solutions in the form of safe, reliable, and affordable service for customers. In addition, the request in this case and the concurrently filed TAM bring to customers

[1] 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.

the benefits of low-cost new and repowered resources that lower net power costs and pass along the savings of federal production tax credits (PTCs)

Q. How is your testimony structured?

A. Section III of my testimony provides an overview of PacifiCorp's last rate case filing. Section IV provides an overview of this rate case filing, including a discussion of key drivers. Section V discusses certain regulatory mechanisms that the Company is proposing in this proceeding that relate to plant generation transition costs and the retirement of Cholla Unit 4. Section VI discusses the Company' proposed regulatory mechanism to recover costs associated with the Company' wildfire mitigation efforts.

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

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

- Authorize an overall increase of $70.8 million[2] or approximately 5.4 percent, which is primarily comprised of (1) an increase in rates of $78.0 million related to a non-net power costs (NPC) revenue requirement of $1,045.7 million; (2) an increase of $17.3 million for the recovery of costs related to the early retirement of Cholla Unit 4; and (3) a decrease of approximately $24.9 million related to the amortization of deferred tax benefits associated with the TCJA results. The support for the overall increase is set forth in my testimony and the testimony of the other Company witnesses;

- Approve as prudent the Company's request to include the incremental additions to the Company's rate base, including Energy Vision 2020 and the Pryor Mountain Wind Project, the installation of emission control retrofits on certain generating plants, the conversion of Naughton Unit 3 to gas, advanced metering infrastructure (AMI), and wildfire mitigation costs for a total rate base of approximately $4.2 billion, as discussed in the testimony of various witnesses in this rate case;

- Approve Exit Dates and issue Exit Orders for coal-fired resources consistent with the dates described in my testimony;

- Approve the proposed Generation Plant Removal Adjustment described in my testimony;

[2] When the impact of the Company's TAM filing is incorporated, the total impact to rates is an increase of $21.6 million.

- Approve the proposed decommissioning balancing account for coal-fired resources that do not operate beyond Oregon's depreciable life;
- Approve the proposed Wildfire Mitigation Cost Recovery Mechanism discussed in my testimony;
- Approve an overall cost of capital of 7.68 percent, which is comprised of a capital structure of 53.52 percent equity, 46.47 percent long-term debt, and 0.01 percent preferred stock as supported by Ms. Nikki L. Kobliha; and a return on equity (ROE) of 10.2 percent as supported by Ms. Ann E. Bulkley;
- Approve as prudent and include in rates costs associated with the Company's wildfire mitigation efforts and costs to repair damaged equipment following the Delta wildfire, as supported in the testimony of Mr. David M. Lucas;
- Approve the changes to Schedule 300, Rule 10, and Rule 11D and the proposals for certain bill credits set forth in the testimony of Ms. Melissa S. Nottingham;
- Approve return of $71.7 million of deferred tax benefits to customers over a three-year period as discussed in the testimony of Ms. McCoy;
- Approve the Company's proposed treatment of costs associated with the closure of Cholla Unit 4 in 2020 as described in the testimony of Ms. McCoy; and
- Approve the innovative and equitable cost of service and rate design proposals set forth in the testimony of Mr. Robert M. Meredith.

Q. Are you also sponsoring exhibits to your testimony?

A. Yes, I am sponsoring Exhibit PAC/201, which is a comparison of PacifiCorp's Oregon rates to national averages.

III. PREVIOUS RATE CASE HISTORY

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

A. PacifiCorp's efficient management of costs has allowed the Company to file only one general rate case in the last seven years. On March 1, 2013, the Company filed its 2013 Rate Case requesting an increase in revenues from Oregon operations for an overall price change of 4.6 percent or $56.0 million. Based on a stipulation agreed to by the parties and approved by the Commission, PacifiCorp was authorized a $23.7 million rate increase.[3]

Q. What is the Company's overall retail average rate change in Oregon since 2013?

A. Since the conclusion of the Company's 2013 Rate Case with rates effective January 1, 2014, the Company's Oregon customers have seen a modest overall average retail rate increase of only 3.0 percent, from 9.27 cents per kilowatt-hour (kWh) to 9.55 cents per kWh. This is well below inflation over this same time period.[4]

Q. How does the overall retail average rate compare to the national average?

A. PacifiCorp's efficient operations and focus on rate stability for customers have resulted in the Company's average price being approximately 11 percent lower than the national average of 10.83 cents per kWh for the 12 months ending December 31, 2018, as reported by the Edison Electric Institute Winter 2019 Typical Bills and Average Rates Report. Attached to my testimony as Exhibit PAC/201 is a chart comparing PacifiCorp's Oregon rates to national averages.

IV. OVERVIEW OF RATE CASE

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

A. There are a number of drivers leading PacifiCorp to filing this rate case at this time. Consistent with Oregon's energy policies, and the 2017 and 2019 IRP action plans, PacifiCorp is transitioning its generation portfolio.[5] As PacifiCorp invests in new renewable resources it is also necessary to address the treatment of costs associated

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[3] Order No. 13-474, at 1.
[4] *CPI Inflation Calculator*, Bureau of Labor Statistics, https://www.bls.gov/data/inflation_calculator.htm (comparing January 2014 to January 2019).
[5] *See* SB 1547, effective date Mar. 8, 2016 (https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled; Docket No. LC 67, PacifiCorp 2017 Integrated Resource Plan filed April 4, 2017; and Docket No. LC 70, PacifiCorp 2019 Integrated Resource Plan filed October 18, 2019).

with existing legacy resources through updated decommissioning and depreciation rates, as discussed in the testimony of Ms. McCoy, and proposals, discussed later in my testimony, to address the removal of coal-fired resources from Oregon rates.

As part of this transition, the Company has either started or completed a number of major capital projects, such as Energy Vision 2020. The rates set in this proceeding will allow PacifiCorp to recover the prudently incurred investments made since the last rate case and enable PacifiCorp to continue the Company's vision to deliver affordable, reliable energy to customers while reducing greenhouse gas emissions. In addition to capital investments, as the energy landscape has shifted in Oregon, this general rate case represents the first opportunity for PacifiCorp to update and modernize its rate design in seven years.

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

A. The test period the Company is proposing is a fully forecasted test year for the 12 months ended December 31, 2021, with the exception of capital additions, which are based on calendar year-end 2020 balances. The testimony of Ms. McCoy discusses the development of the test year.

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

A. The Company is requesting approval of an overall rate of return of 7.68 percent. The overall rate of return is comprised of a 10.2 percent ROE as supported by Ms. Bulkley. As explained by Ms. Kobliha, PacifiCorp is requesting approval of a capital structure that is comprised of 53.52 percent equity, 46.47 percent long-term debt, and 0.01 percent of preferred stock. Ms. McCoy applies the overall rate of return to the Company's cost of service.

Q. Is the Company using a new inter-jurisdictional allocation methodology in this rate case?

A. Yes. The Commission approved the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol) on January 23, 2020.[6] The Company used the 2020 Protocol to develop the revenue requirement in this proceeding.

Q. Has the Company incorporated the remaining benefits associated with the TCJA in this general rate case?

A. Yes. PacifiCorp's Oregon customers have already experienced a decrease in rates through PacifiCorp's pass-through of the change in the corporate income tax rate established by the TCJA. This general rate case filing incorporates the remaining impacts of the TCJA that have not already been addressed in docket UM 1985. In Order 19-028, in docket UM 1985, the Commission authorized the Company to return to customers the 2018 TCJA deferral balance to customers over a one-year period ending January 31, 2019, and the 2019 TCJA deferral balance over a one-year period ending December 31, 2020.[7] Per Order 19-028, any remaining 2019 balance at December 31, 2020, and the 2020 deferral balance are to be addressed in this general rate case filing.

Following Order 19-028, in docket UE 352, the Company's 2019 Renewable Adjustment Clause (RAC) proceeding, the Commission approved a stipulation that resolved among other issues, the use of the TCJA deferral balance. Specifically, the

[6] *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).
[7] *See In the matter of PacifiCorp, dba Pacific Power, Application for an Accounting Order and Request for Amortization Related to the Federal Tax Act,* Docket No. UM 1985, Order No. 19-028 (Jan. 29, 2019).

Oregon-allocated net book value of the undepreciated plant that is replaced as a result of wind repowering has been offset with the non-protected Excess Deferred Income Tax benefits resulting from the TCJA.[8] The remaining tax reform benefits are available to customers as discussed in the testimony of Ms. Kobliha. As proposed by the Company in the testimony of Ms. McCoy, the remaining tax reform benefits will decrease customer rates by $24.9 million annually for three years. The all-in effect of the Company's request in this general rate case filing is addressed in the testimony of Mr. Meredith.

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

A. The major drivers of the Company's general rate case filing are: (1) capital additions; (2) updated depreciation rates and decommissioning costs; (3) new regulatory mechanisms to address changing risks and policies; and (4) updated rate design. I discuss each of these drivers in more detail below.

Q. Please describe the capital additions drivers in this rate request.

A. The primary driver is the Company's investment in renewable generation, including Energy Vision 2020 and the Pryor Mountain Wind Project. Other capital additions include emissions control retrofit projects at certain coal-fired resources, wildfire mitigation efforts, and fish passage upgrades at the Lewis River hydroelectric facility. These capital investments are more fully discussed in the testimonies of Mr. Rick T. Link, Mr. Chad A. Teply, Mr. Lucas, and Mr. Timothy J. Hemstreet, respectively.

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[8] *In the matter of PacifiCorp, dba Pacific Power, Pacific Power's 2019 Renewable Adjustment Clause*, Docket No. UE 352, Order No. 19-304 (Sept. 16, 2019).

Q. What are the major components of Energy Vision 2020?

A. Energy Vision 2020 consists of two major components, both of which are included in this case: (1) wind repowering; and (2) investments in new wind and transmission. PacifiCorp identified and presented its Energy Vision 2020 strategy in its 2017 IRP, which was acknowledged by the Commission.[9]

Q. Please describe PacifiCorp's wind repowering component of Energy Vision 2020.

A. As explained in the testimony of Mr. Hemstreet, the Energy Vision 2020 wind repowering component involves upgrading PacifiCorp's existing wind facilities to increase the amount of zero-fuel-cost energy they produce. By complying with federal tax requirements for wind repowering and completing the work by the end of 2020, PacifiCorp is also able to renew the federal PTCs on all repowered wind facilities for another 10 years. The wind repowering component includes all of PacifiCorp's 13 wind facilities, representing 1,039.9 megawatts (MW) of installed wind capacity. In docket UE 352, the Commission approved nine of the Company's wind repowering projects; in docket UE 369, two of the repowering projects are subject to an all-party stipulation that requests Commission approval.[10] In this general rate case filing, the Company is requesting that the Commission allow the Company to include in rate base the Foote Creek I project, which is addressed in detail by Mr. Hemstreet.

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[9] *In the matter of PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan*, Docket No. LC 67, Order No. 18-138, at 12 (Apr. 27, 2018).

[10] Order No. 19-304, at 8-9 (Sept. 16, 2019); *In the matter of PacifiCorp, dba Pacific Power, 2020 Renewable Adjustment Clause*, Docket No. 369, Stipulation filed Jan. 31, 2020 (The Commission has not yet ruled on the Stipulation entered into by the parties in Docket No. UE 369); The Rolling Hills wind project located in Wyoming will also be repowered but it is not included in the proposed Oregon rates in this proceeding and the Company has not requested to bring it into Oregon rates through the RAC in either Docket No. UE 352 or Docket No. UE 369.

Q. Does the Foote Creek I repowering project provide quantifiable benefits to customers?

A. Yes. As described in the testimony of Mr. Hemstreet and Mr. Link, the Foote Creek I project produces net customer benefits across a range of price-policy scenarios.

Q. Please describe Energy Vision 2020's new wind investments.

A. By the end of 2020, PacifiCorp will add 1,150 MW of new wind resources in Wyoming. These resources are three facilities built by the Company, the 500 MW TB Flats I and II facilities and the 250 MW Ekola Flats project, and one facility that is a combined build-own transfer and purchase power agreement, the 400 MW Cedar Springs facility. As Mr. Teply explains, because "safe harbor" wind turbines purchased in 2016 will be used to construct these facilities, each will be eligible for full PTCs if they are in service by the end of 2020. As explained by Mr. Link, these facilities were carefully selected to maximize value to customers in the 2017R Request for Proposals (RFP), which was monitored by independent evaluators from both Oregon and Utah.

Q. Please describe Energy Vision 2020's new transmission investments.

A. PacifiCorp is also building a new, 140-mile Gateway West transmission segment—the 500 kV Aeolus-to-Bridger/Anticline Transmission Project, plus generation interconnection network upgrades—in Wyoming to enable the new Energy Vision 2020 wind generation. As explained by Mr. Richard A. Vail, regional and Company transmission plans called for building the Aeolus-to-Bridger/Anticline Transmission Project by 2024, but by accelerating the construction date, the Company can use PTC benefits from wind facilities to offset costs.

Q. What is the status of the construction of the new wind and transmission facilities?

A. The new wind and transmission facilities are scheduled to be in service in the last quarter of 2020, before the rate effective date in this case. This will ensure that the new wind facilities qualify for PTCs. Mr. Teply and Mr. Vail provide more information on the construction timelines.

Q. Do the combined wind and transmission investments provide quantifiable net benefits to customers?

A. Yes. As Mr. Link explains in his testimony, the investments are a unique opportunity for customers to add needed and valuable renewable generation and transmission resources and reduce overall costs in the process.

Q. Please describe the updated depreciation rates and decommissioning costs driver in this rate request.

A. On September 13, 2018, the Company filed an application and supporting testimony for an accounting order authorizing a change in depreciation rates effective as of January 1, 2021.[11] Concurrent with the filing of this rate case, the Company has supplemented that filing to update the depreciable lives to be consistent with the 2019 IRP and the 2020 Protocol, and to include the revised decommissioning costs consistent with the Decommissioning Study filed in that proceeding. The updated depreciation rates, which include the revised decommissioning costs, are reflected in the rate request in this proceeding. See Ms. McCoy's direct testimony with respect to the calculation of the revenue requirement using the updated depreciation rates.

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[11] *In the matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates,* Docket No. UM 1968, Application filed Sept. 13, 2018.

Q. Please describe the new regulatory mechanisms that address changing risks and policies.

A. The Company has been and will continue to encounter costs associated with the retirement of coal-fired resources on its system and the elimination of coal from Oregon rates by 2030 as required by Senate Bill (SB) 1547.[12] Further, PacifiCorp, like many other western electric utilities, has been mitigating the increased risk of wildfires, which can be devastating to its customers and its facilities. To address these changing dynamics, PacifiCorp is proposing two mechanisms, one related to coal-fired resources, the Generation Plant Removal Adjustment, and one related to the increased wildfire risk, the Wildfire Cost Recovery Mechanism. I address these proposals in Section V and Section VI of my testimony.

Q. Please describe the updated rate design.

A. As I noted earlier, the Company has not filed a rate case since 2013. As a result, the Company is proposing a number of changes to how rates are currently designed, including having a separate basic charge for multi-family customers; and modernizing the time of use periods for its large non-residential customers and increasing the differential between on- and off-peak energy. The Company is also proposing several innovative pricing pilots, including a residential time of use pilot. All of the rate design proposals are discussed in Mr. Meredith's direct testimony.

[12] *See* Section 1(2) of SB 1547.

V. OREGON ENERGY TRANSITION

Q. What is your understanding of the Oregon energy policy regarding coal-fired resources?

A. My understanding is that Section 1 of SB 1547 instructs utilities to eliminate the cost and benefits of coal-fired resources from retail electric rates on or before January 1, 2030.

Q. Has the Company proposed a process to facilitate the removal of the costs and benefits of coal-fired resources from Oregon rates?

A. Yes. The recently approved 2020 Protocol[13] details the process by which Oregon can exit coal-fired resources by a date certain.

Section 4.1 of the 2020 Protocol outlines a process by which state commissions may issue "Exit Orders"[14] that provide for specific "Exit Dates"[15], after which the state will no longer receive any benefits or be subject to any new costs related to the resource for which the Exit Order was issued. The 2020 Protocol states that Exit Orders may be established through the approval of the 2020 Protocol, in depreciation dockets, general rate cases, or other appropriate regulatory proceedings. In requesting approval of the 2020 Protocol, the Company did not seek and the Commission did not approve issuance of Exit Orders or Exit Dates for coal-fired resources;[16] the Company now requests the Commission issues Exit Orders with specific Exit Dates for the majority of PacifiCorp's coal-fired resources.

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[13] *See* Order No. 20-024.
[14] 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.
[15] 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.
[16] *See* Order No. 20-024, at 7-8.

Q. Did the 2020 Protocol include agreed-upon Exit Dates for Oregon for coal-fired resources?

A. Yes. Where possible, the 2020 Protocol sets forth Oregon Exit Dates for coal-fired resources that comply with SB 1547 (i.e., before December 31, 2029), coincide with the 2019 IRP preferred portfolio (i.e., common closure dates for all states), or allow for potential realignment of the coal-fired resources to other states. PacifiCorp, Commission Staff, the Oregon Citizens' Utility Board, the Alliance of Western Energy Consumers, and Sierra Club, all signatories to the 2020 Protocol, agreed to support the Oregon Exit Dates set forth in the 2020 Protocol for all of PacifiCorp's coal-fired resources, with the exception of Hayden. These Exit Dates are set forth in Table 1 below:

Table 1: Proposed Oregon Exit Dates

Coal-Fired Resource	Recommended Oregon Exit Date
Cholla 4	December 31, 2020
Jim Bridger 1	December 31, 2023
Craig 1	December 31, 2025
Jim Bridger 2	December 31, 2025
Jim Bridger 3	December 31, 2025
Jim Bridger 4	December 31, 2025
Naughton 1	December 31, 2025
Naughton 2	December 31, 2025
Craig 2	December 31, 2026
Colstrip 3	December 31, 2027
Colstrip 4	December 31, 2027
Dave Johnston 1	December 31, 2027
Dave Johnston 2	December 31, 2027
Dave Johnston 3	December 31, 2027
Dave Johnston 4	December 31, 2027
Hunter 1	December 31, 2029
Hunter 2	December 31, 2029
Hunter 3	December 31, 2029
Huntington 1	December 31, 2029
Huntington 2	December 31, 2029
Wyodak	December 31, 2029

Q. Is the Company requesting the Commission issue Exit Orders for the Exit Dates identified in Table 1 above and in the 2020 Protocol?

A. Yes, the Company is requesting the Commission issue Exit Orders with Exit Dates for 23 of PacifiCorp's 24 coal-fired resources.[17] The Company's requested Exit Dates are discussed in greater detail below.

For Hunter Units 1-3, Huntington Units 1-2, and Wyodak, the Company requests the Commission approve Exit Orders with Exit Dates of December 31, 2029,

[17] Hayden is the only unit for which the Company is not currently requesting an Exit Order with an Exit Date. Per the 2020 Protocol, the Company will subsequently bring forth a proposal.

as reflected in Table 1 above. The Exit Orders and Exit Dates for these units are necessary to comply with the mandate contained in SB 1547 to remove coal-fired resources from rates by December 31, 2029.

For Jim Bridger Unit 1, Naughton Units 1-2, Dave Johnston Units 1-4, Craig Units 1-2, Cholla Unit 4, and Colstrip Units 3-4, the Company requests the Commission approve Exit Orders with Exit Dates as set forth in Table 1 above and consistent with the lives identified in the 2019 IRP.[18] Per the 2019 IRP, the Company anticipates that these units will cease operation or the Company will terminate its ownership interest by the requested Exit Dates.

Finally, for Jim Bridger Units 2-4, the Company requests the Commission approve Exit Orders with Exit Dates set forth in Table 1 above and consistent with the Company's requested depreciable lives in the 2018 Depreciation Study.[19] Jim Bridger Units 2-4 are unique in that the requested Exit Dates are in advance of the lives identified in the 2019 IRP[20] and in advance of the compliance deadline for SB 1547.

Q. Please explain the policy basis for issuing an Exit Order with an Exit Date for Jim Bridger Units 2-4 of December 31, 2025.

A. An Exit Date of 2025 for Jim Bridger Units 2-4 aligns with Oregon's policy to transition from coal-fired resources. In addition, the Exit Date for Jim Bridger Units

[18] *In the matter of PacifiCorp, dba Pacific Power, 2019 Integrated Resource Plan*, Docket No. LC 70, PacifiCorp's 2019 Integrated Resource Plan, at 13 (Oct. 18, 2019). Cholla Unit 4 is identified as having a retirement date no later than January 1, 2023. The Company recently committed to closing Cholla Unit 4 by the end of 2020.

[19] *In the matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates,* Docket No. UM 1968, Exhibit PAC/202, filed Sep. 13, 2018.

[20] The 2019 IRP identifies an operational life for Jim Bridger 2 of 2028 and operational lives of 2037 for Jim Bridger Units 3-4.

2-4 represents a trade-off between the potential for continued NPC benefits associated with including the units in rates through the operational lives identified in the 2019 IRP, and the certainty of decommissioning and remediation liability of Jim Bridger Units 2-4, commensurate with Oregon's current allocation. Per the 2020 Protocol, if Oregon exits a coal-fired resource in advance of closure, Oregon receives certainty with regard to the level of decommissioning and remediation costs allocated to Oregon; for Jim Bridger Units 2-4, Oregon will only be allocated its estimated share of decommissioning and remediation costs. To the extent that actual decommissioning and remediation costs incurred at the time of closure differ from what was estimated, and Oregon has already exited the units, that cost variance will not be recovered from Oregon customers.

Q. Why are Exit Orders necessary now?

A. Exit Orders for the Hunter, Huntington, and Wyodak units at this time provides certainty with regard to PacifiCorp's compliance with SB 1547. For coal-fired resources anticipated to cease operation or for which the Company is anticipated to terminate its ownership interest before December 31, 2029, issuance of Exit Orders now provides a clear pathway for PacifiCorp to remove the costs of these units from rates consistent with the cessation of operation or PacifiCorp's termination of its ownership interest. In addition, in the event that PacifiCorp continues to operate a coal-fired resource beyond Oregon's Exit Date, an Exit Order will allow time for states other than Oregon (i.e., Idaho, Utah, and Wyoming) to determine whether to take an increased allocation of the costs and benefits of such coal-fired resource, consistent with the 2020 Protocol.

Q. Does the 2020 Protocol specify timelines for receiving Exit Orders from Oregon?

A. Yes. Parties to the 2020 Protocol will endeavor to have Exit Orders issued on or before December 15, 2020, for the resources with 2027 recommended Exit Dates, and Exit Orders issued on or before December 31, 2023, for the coal-fired resources with Exit Dates in 2029.

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

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

Q. How does PacifiCorp propose to remove coal-fired resources with an Exit Order from electric rates in a timely manner?

A. PacifiCorp requests that the Exit Order also provide PacifiCorp the ability to effectively remove the coal-fired resource from its rates as of the Exit Date through a separate tariff adjustment until such time that base rates can be adjusted in a general rate case. The Company is proposing a Generation Plant Removal Adjustment in this case to facilitate the removal of coal-fired resources from rates consistent with approved Exit Dates.

Q. Please describe the Generation Plant Removal Adjustment.

A. The Generation Plant Removal Adjustment is a separate tariff that will allow the Company to both recover costs associated with the closure of or termination of ownership interest in (i.e., removal) generation plant (e.g., coal-fired resources), and to credit to customers the revenue requirement associated with generation plant that is removed from rates between general rate cases. This mechanism will allow for the timely recovery of closure or removal costs while also ensuring customers timely receive the benefits of removing generation plant from rates.

Q. How will the Generation Plant Removal Adjustment recover closure or removal costs?

A. In this general rate case, subsequent general rate cases, or stand-alone filings, PacifiCorp will identify specific closure or removal costs for recovery through the Generation Plant Removal Adjustment. PacifiCorp anticipates that the circumstances associated with the closure or removal of generation plant will be unique and, as such, will make specific proposals identifying specific costs for recovery through either general rate case filings or stand-alone filings. In this general rate case, as described later in my testimony and in the testimony of Ms. McCoy, the Company is requesting the recovery of certain closure costs associated with the early closure of Cholla Unit 4.

Q. How will the Generation Plant Removal Adjustment timely reflect to customers the removal of generation plant from rates?

A. In this general rate case and any subsequent general rate that occurs before the Exit Date of a coal-fired resource, the revenue requirement for each coal-fired resource will be clearly identified in the final compliance filing. At least 30 days in advance of the Exit Date, the Company will file an advice letter to credit to customers through a separate tariff adjustment the revenue requirement, approved in the most-recent general rate case, associated with the coal-fired resource that is to come out of rates through operation of the Exit Order and Exit Date. The revenue requirement will include all costs associated with the coal-fired resources including the depreciation expense, ROE, and operations and maintenance expense, as approved in the most-recent general rate case. Coal fuel expense will be removed through the annual power cost forecast mechanism. In the next general rate case following the Exit Date for a coal-fired resource, the coal-fired resource will be removed from base rates and the associated tariff adjustment revenue requirement will be set to zero. This treatment will allow the lower costs associated with the closure or removal of coal-fired resources from rates to immediately flow through to customers without the need for a general rate case, effectively removing the coal-fired resource from rates contemporaneous with the Exit Date.

Q. How does an Exit Order affect decommissioning costs?

A. Per the 2020 Protocol, if a coal-fired resource is included in Oregon rates at the time it is retired, or PacifiCorp terminates its ownership interest in the resource, Oregon is allocated its share of the actual decommissioning cost. If Oregon has issued an Exit Order and PacifiCorp continues operation of the coal-fired resource beyond the Exit Date then Oregon will only pay the estimated decommissioning costs through the time of the Exit Date.

Q. How does the Company propose that decommissioning costs be treated for coal-fired resources that may operate beyond the Exit Date?

A. Consistent with the 2020 Protocol, the Company recently contracted with a third party to conduct a decommissioning study for certain coal-fired resources, namely Hunter, Huntington, Dave Johnston, Jim Bridger, Naughton, Wyodak, and Hayden. The results of this study have been filed in the 2018 Depreciation Study and incorporated into the depreciation rates included in this case. If a coal-fired resource continues operations beyond the Exit Date, the depreciation expense that includes decommissioning costs are simply removed from rates with an advice letter and no further adjustment or treatment is necessary. A decommissioning study is expected to be completed for the Colstrip plant in March 2020 and will be incorporated into the

2018 Depreciation Study at that time. Additionally, an update to the decommissioning study is scheduled to take place in 2024.

Q. What is PacifiCorp's proposal for the treatment of decommissioning costs for coal-fired resources that PacifiCorp does not operate beyond the Exit Date?

A. In this scenario, the Company proposes that Oregon be allocated its share of the actual decommissioning costs per the 2020 Protocol. To ensure Oregon customers only pay actual decommissioning costs, PacifiCorp recommends treatment as follows:

- Creation of a balancing account to track the coal-fired resource decommissioning costs collected through rates, and the actual non-capital decommissioning expenditures incurred contemporaneous with decommissioning and environmental remediation activities;
- Until the end of the remediation process, PacifiCorp will update the decommissioning costs in each subsequent general rate case;
- Decommissioning cost projections ultimately included in rates will be net of insurance proceeds so that the Company will recover only the actual prudently incurred decommissioning costs; and
- At the end of the remediation process, PacifiCorp will amortize the decommissioning balancing account over a one-year period.

Q. Please describe the recovery of Cholla Unit 4.

A. As discussed by Mr. Stefan A. Bird and Mr. Link, PacifiCorp is retiring Cholla Unit 4 by December 31, 2020. PacifiCorp is proposing that the costs associated with the retirement and decommissioning of Cholla Unit 4 be recovered through the Generation Plant Closure Adjustment. Therefore, the proposed revenue requirement in this proceeding does not include Cholla Unit 4 retirement costs, including construction work-in-progress; unused materials and supply inventory; liquidated damages related to the early termination of the related coal supply agreement; and decommissioning costs. The Company proposes to remove Cholla Unit 4 plant balances from rate base as of December 31, 2020. Please see Ms. McCoy's direct testimony for a discussion of the regulatory asset and related amortization, and carrying charges to be recovered through the proposed adjustment.

VI. WILDFIRE MITIGATION COST RECOVERY MECHANISM

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

A. In this section of my testimony, I discuss the Wildfire Mitigation Cost Recovery Mechanism.

Q. What is the Wildfire Mitigation Cost Recovery Mechanism?

A. PacifiCorp proposes a Wildfire Mitigation Cost Recovery Mechanism to recover its capital expenditures related to wildfire mitigation. As discussed more fully in the testimony of Mr. Lucas, while wildfire risk is inherent in operating an electric utility, particularly in the West, the increasing frequency, severity, and costs of wildfires has heightened the focus on wildfire risk mitigation plans by electric utilities. PacifiCorp has taken this increased risk seriously and developed a capital intensive wildfire mitigation plan that is incremental to its routine safety and maintenance programs to further protect its customers, employees, and facilities from catastrophic wildfires. Please see the direct testimony of Mr. Lucas for a discussion regarding the increased risks of wildfire and the specific actions PacifiCorp is taking to mitigate these risks.

In addition to wildfire risk, the Company is currently unable to receive timely recovery of its capital expenditures for wildfire mitigation activities outside of a general rate case proceeding. It is my understanding that the Commission determined that Oregon Revised Statute 757.259(2)(e), which allows utilities to seek accounting orders to defer costs in between rate cases, does not provide the Commission authority to allow deferrals of any costs related to capital investments.[21] Although the Company does not have a pre-determined level of capital spend that triggers the need for a general rate case, the levels of forecast capital spend for wildfire mitigation, under normal circumstances,[22] would not drive the need for rate case filings. In the absence of the ability to request deferral treatment, however, the Company faces the prospect of taking multi-year regulatory lag on important and significant capital expenditures for wildfire mitigation, or increased general rate case activity. The level of forecast capital spend for wildfire mitigation, discussed in the testimony of Mr. Lucas, should not, on its own, drive annual rate case filings, which would otherwise be necessary for the Company to achieve timely recovery of these costs. PacifiCorp requests the Commission approve the proposed Wildfire Mitigation Cost Recovery Mechanism as a flexible form of ratemaking in response to a rapidly changing environment related to wildfire risk and to ensure a process to minimize regulatory lag for recovery of these important capital investments. Minimizing regulatory lag is particularly important at this time of increased capital expenditures, as discussed more in the testimony of Ms. Kobliha.

[21] *See In the matter of the Public Utility Comm'n of Oregon, Investigation of the Scope of the Commission's Authority to Defer Capital Costs,* Docket No. UM 1909, Order No. 18-423, at 8 (Oct. 29, 2018).
[22] I.e., the ability to defer capital expense.

Q. Have any costs related to wildfire mitigation been included in this general rate case?

A. Yes. PacifiCorp's wildfire mitigation capital expenditures through 2020 have been included in this general rate case. Thus, this proposed mechanism focuses on the Company's recovery of capital expenditures for the years 2021 and beyond, which are discussed in the testimony of Mr. Lucas.

Q. Please describe how the Wildfire Mitigation Cost Recovery Mechanism is structured.

A. If the Commission approves the Company's proposed mechanism in this proceeding, the Company would submit the 2021 forecasted wildfire mitigation expenditures for prudence review in the first quarter of 2021. The Company proposes a six-month time period for review of the expenditures, followed by biannual filings to update the rate to reflect the capital expenditures for each six-month period. These filings would continue until the Company's next filed rate case. As with the RAC, the rate updates would be considered compliance filings and not subject to the 30-day review period required for regular advice filings. Table 2 below provides an example of such filings for 2021 and 2022 should the Commission approve the mechanism.

Table 2: Example of 2021 and 2022 Filings for the Wildfire Mitigation Cost Recovery Mechanism

	Summary of Filing	Proposed Filing Date	Proposed Effective Date
Cost Recovery Filing for 2021	Submit forecasted capital spend for calendar year 2021 for prudence review.	January 15, 2021	Order issued by May 31, 2021
1st Cost Update	Update rate to reflect capital spend for projects placed in service January 1 – June 30.	June 15, 2021	July 1, 2021
2nd Cost Update	Update rate to reflect capital spend for projects placed in service July 1 – December 30.	December 15, 2021	January 1, 2022
Cost Recovery Filing for 2022	Submit forecasted capital spend for calendar year 2022 for prudence review.	January 15, 2022	Order issued by May 31, 2022
1st Cost Update	Update rate to reflect capital spend for projects placed in service January 1 – June 30.	June 15, 2022	July 1, 2022
2nd Cost Update	Update rate to reflect capital spend for projects placed in service July 1 – December 30.	December 15, 2022	January 1, 2023

Q. Are there other examples of similar mechanisms approved by the Commission?

A. Yes. The Company modeled the Wildfire Cost Recovery Mechanism on the RAC, which similarly allows for the Commission to consider new capital additions on a stand-alone basis. Although the RAC is specifically authorized by statute, my understanding is that the Commission has authority to establish automatic adjustment clauses in the absence of specific statutory direction. In this instance, given the policy interest of the state in mitigating wildfires, it is appropriate for the Commission to approve a specific cost-recovery mechanism that allows for timely review and recovery of the capital necessary for PacifiCorp to undertake the incremental activities necessary to effectively mitigate wildfire risk on its system for the benefit of PacifiCorp customers and the state.

Q. Does the proposed Wildfire Cost Recovery Mechanism balance the need for flexible ratemaking treatment with customer protections?

A. Yes. The Wildfire Cost Recovery Mechanism is narrowly tailored to address stand-alone cost recovery of a discrete set of incremental costs associated with a new and emerging risk: wildfire. As discussed in the testimony of Mr. Lucas, not only is the physical risk of wildfire increasing, but insurance markets are also responding to the changing wildfire risk. It is critical that PacifiCorp take immediate steps to mitigate the risk of wildfires and PacifiCorp has done so by implementing wildfire mitigation actions as early as 2018. PacifiCorp anticipates increasing wildfire mitigation activity on its system and in Oregon over at least the next five years as PacifiCorp continues to implement the actions outlined in the testimony of Mr. Lucas. As Mr. Lucas discusses, this timeline is necessary to accommodate resource constraints as utilities throughout the West undertake similar mitigation activities, seasonal access to facilities, and labor constraints due to a national shortage of qualified workers to perform necessary work. For these reasons, it is appropriate for the Commission to exercise its discretion to implement an automatic adjustment clause mechanism to allow for recovery of wildfire mitigation costs.

In addition, the structure of the proposed Wildfire Mitigation Cost Recovery Mechanism provides full opportunity for prudence review by the Commission and stakeholders, similar to the RAC. Cost recovery is not guaranteed, assets will be required to be in-service by the rate effective date, and regulatory lag is not entirely eliminated. This structure appropriately balances customer protections with the need for flexible ratemaking treatment.

VII. CONCLUSION

Q. Please summarize your recommendations to the Commission.

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

- Authorize an overall increase of $70.4 million or approximately 5.4 percent, which is comprised of (1) an increase in rates of $78.0 million related to a non-NPC revenue requirement of $1,045.7 million; (2) an increase of $17.3 million for the recovery of costs related to the early retirement of Cholla Unit 4; and (3) a decrease of approximately $24.9 million related to the amortization of deferred tax benefits associated with the TCJA results;
- Approve the Company's total rate base of approximately $4.2 billion;
- Approval of Exit Orders with specified Exit Dates for all but one of PacifiCorp's coal-fired resource units;
- Approval of the Generation Plant Closure Adjustment;
- Approval of the Company's proposed decommissioning balancing account;
- Approval of the Company's proposed treatment of Cholla Unit 4 closure costs; and
- Approval of the Wildfire Mitigation Cost Recovery Mechanism.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/201
Witness: Etta Lockey

BEFORE THE PUBLIC UTILITY COMMISSION

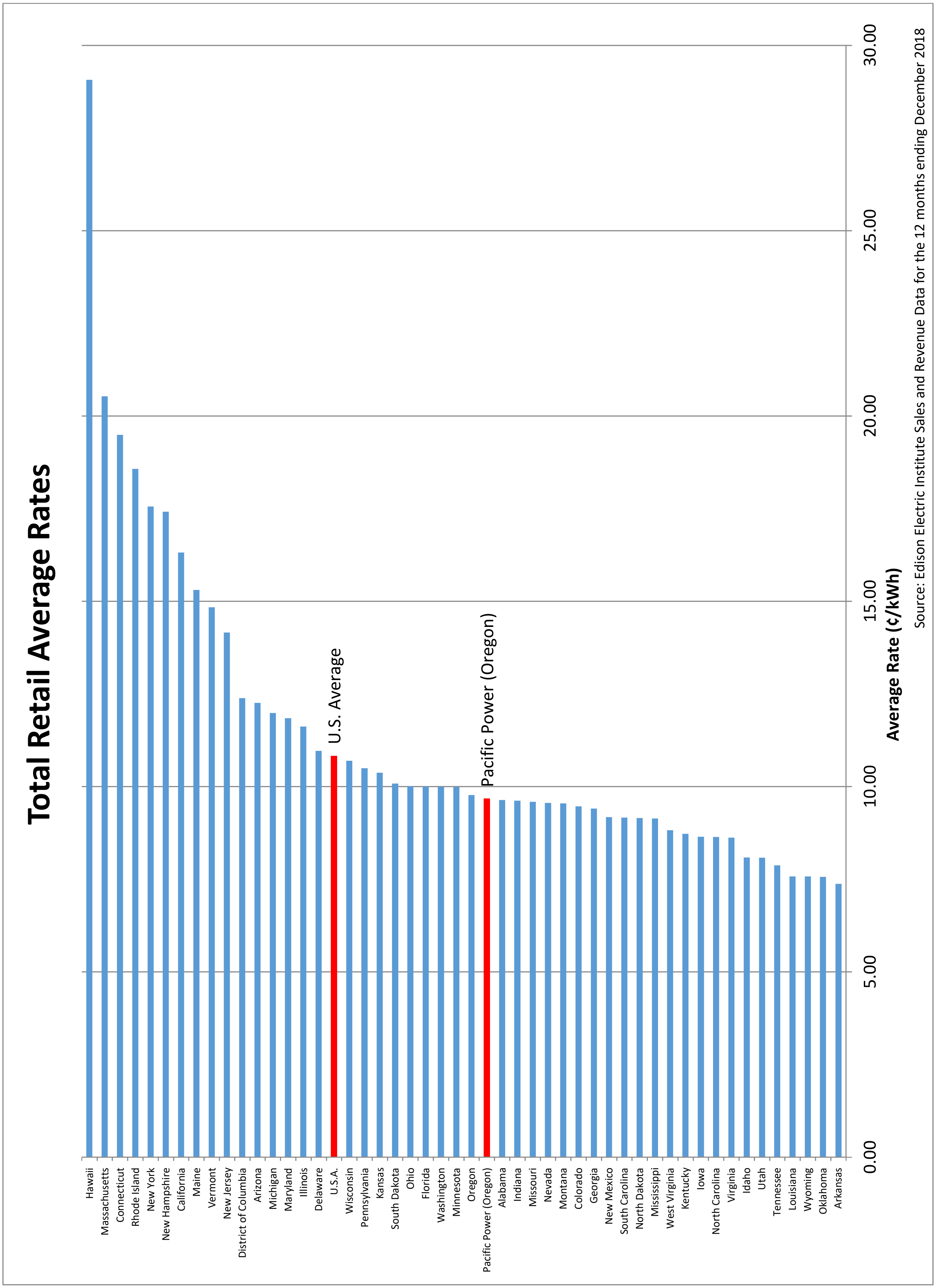
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Etta Lockey

PacifiCorp's Oregon Rates Compared to National Averages

February 2020


Total Retail Average Rates
U.S. Average
Pacific Power (Oregon)
Hawaii
Massachusetts
Connecticut
Rhode Island
New York
New Hampshire
California
Maine
Vermont
New Jersey
District of Columbia
Arizona
Michigan
Maryland
Illinois
Delaware
U.S.A.
Wisconsin
Pennsylvania
Kansas
South Dakota
Ohio
Florida
Washington
Minnesota
Oregon
Pacific Power (Oregon)
Alabama
Indiana
Missouri
Nevada
Montana
Colorado
Georgia
New Mexico
South Carolina
North Dakota
Mississippi
West Virginia
Kentucky
Iowa
North Carolina
Virginia
Idaho
Utah
Tennessee
Louisiana
Wyoming
Oklahoma
Arkansas
0.00
5.00
10.00
15.00
20.00
25.00
30.00
Average Rate (¢/kWh)
Source: Edison Electric Institute Sales and Revenue Data for the 12 months ending December 2018

Total Retail Average Rates, 12 Months Ending Dec 2018

Ordered by Region

Region	State	Total Retail Average Rate (in cents/kWh)
New England	Connecticut	19.50
	Maine	15.31
	Massachusetts	20.54
	New Hampshire	17.42
	Rhode Island	18.58
	Vermont	14.84
Mid-Atlantic	New Jersey	14.16
	New York	17.56
	Pennsylvania	10.50
East North Central	Illinois	11.63
	Indiana	9.62
	Michigan	11.99
	Ohio	10.01
	Wisconsin	10.70
West North Central	Iowa	8.65
	Kansas	10.38
	Minnesota	9.99
	Missouri	9.59
	North Dakota	9.15
	South Dakota	10.08
South Atlantic	Delaware	10.97
	District of Columbia	12.39
	Florida	10.01
	Georgia	9.41
	Maryland	11.85
	North Carolina	8.64
	South Carolina	9.17
	Virginia	8.63
	West Virginia	8.83
East South Central	Alabama	9.64
	Kentucky	8.73
	Mississippi	9.14
	Tennessee	7.88
West South Central	Arkansas	7.38
	Louisiana	7.58
	Oklahoma	7.57
	Texas	7.33
Mountain	Arizona	12.27
	Colorado	9.47
	Idaho	8.09
	Montana	9.55
	Nevada	9.56
	New Mexico	9.18
	Utah	8.08
	Wyoming	7.58
Pacific	California	16.32
	Oregon	9.78
	Washington	10.00
Hawaii	Hawaii	29.07
U.S.A.	U.S.A.	10.83

Alphabetical

State	Average Rate
Alabama	9.64
Arizona	12.27
Arkansas	7.38
California	16.32
Colorado	9.47
Connecticut	19.50
Delaware	10.97
District of Columbia	12.39
Florida	10.01
Georgia	9.41
Hawaii	29.07
Idaho	8.09
Illinois	11.63
Indiana	9.62
Iowa	8.65
Kansas	10.38
Kentucky	8.73
Louisiana	7.58
Maine	15.31
Maryland	11.85
Massachusetts	20.54
Michigan	11.99
Minnesota	9.99
Mississippi	9.14
Missouri	9.59
Montana	9.55
Nevada	9.56
New Hampshire	17.42
New Jersey	14.16
New Mexico	9.18
New York	17.56
North Carolina	8.64
North Dakota	9.15
Ohio	10.01
Oklahoma	7.57
Oregon	9.78
Pennsylvania	10.50
Rhode Island	18.58
South Carolina	9.17
South Dakota	10.08
Tennessee	7.88
Texas	7.33
U.S.A.	10.83
Utah	8.08
Vermont	14.84
Virginia	8.63
Washington	10.00
West Virginia	8.83
Wisconsin	10.70
Wyoming	7.58

Ordered by Rate

State	Average Rate (¢/kWh)	
Texas	7.33	
Arkansas	7.38	
Oklahoma	7.57	
Wyoming	7.58	
Louisiana	7.58	
Tennessee	7.88	
Utah	8.08	
Idaho	8.09	
Virginia	8.63	
North Carolina	8.64	
Iowa	8.65	
Kentucky	8.73	
West Virginia	8.83	
Mississippi	9.14	
North Dakota	9.15	
South Carolina	9.17	
New Mexico	9.18	
Georgia	9.41	
Colorado	9.47	
Montana	9.55	
Nevada	9.56	
Missouri	9.59	
Indiana	9.62	
Alabama	9.64	
Pacific Power (Oregon)	9.68	-11%
Oregon	9.78	
Minnesota	9.99	
Washington	10.00	
Florida	10.01	
Ohio	10.01	
South Dakota	10.08	
Kansas	10.38	
Pennsylvania	10.50	
Wisconsin	10.70	
U.S.A.	10.83	
Delaware	10.97	
Illinois	11.63	
Maryland	11.85	
Michigan	11.99	
Arizona	12.27	
District of Columbia	12.39	
New Jersey	14.16	
Vermont	14.84	
Maine	15.31	
California	16.32	
New Hampshire	17.42	
New York	17.56	
Rhode Island	18.58	
Connecticut	19.50	
Massachusetts	20.54	
Hawaii	29.07	

(Source:Typical Bills and Average Rates Report, Winter 2019, Edison Electric Institute)

Pacific Power (Washington)	8.39
Rocky Mountain Power Total (Weighted Average of Utah, Idaho, & Wyoming average rates)	7.81
Pacific Power Total (Weighted Average of Oregon, Washington, & California average rates)	9.56
PacifiCorp Total (Weighted Average of Oregon, Washington, California, Utah, Idaho, & Wyoming average rates)	8.37

Docket No. UE 374
Exhibit PAC/300
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Nikki L. Kobliha

February 2020

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ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp.

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. I am testifying for PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

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, provides information about the way PacifiCorp is implementing the effects of the Tax Cuts and Jobs Act (TCJA) consistent with recent orders issued by the Public Utility Commission of Oregon (Commission), and supports PacifiCorp's projected pension costs.

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 53.52 percent and provide evidence demonstrating why that level is appropriate and benefits customers. I explain why the recommended equity ratio is required to maintain PacifiCorp's current credit ratings, which provide for a more competitive cost of debt and overall cost of capital and facilitate continued access by the Company to the capital markets over the long term. This capital structure enables the Company's continued investment in infrastructure to provide safe and reliable service from clean energy resources at reasonable costs. I also support PacifiCorp's proposed cost of long-term debt of 4.77 percent and cost of preferred stock of 6.75 percent.

Regarding the implementation of the TCJA, I set forth PacifiCorp's recommendations on how TCJA benefits should be reflected in rates and quantify certain TCJA balances, including Excess Deferred Income Tax (EDIT) balances, and discuss how protected EDIT is being amortized.

Finally, regarding PacifiCorp's projected pension costs, I explain the reasonableness of the costs associated with PacifiCorp's defined pension plans.

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

A. PacifiCorp proposes an overall cost of capital of 7.68 percent. This cost includes the return on equity recommendation of 10.2 percent as supported by the direct testimony of Ms. Ann E. Bulkley and the capital structure and costs set forth in Table 1.

Table 1: Overall Cost of Capital

Component	$m	% of Total	Cost %	Wtd Ave Cost %
Long-Term Debt	$8,433	46.47%	4.77%	2.22%
Preferred Stock	2	0.01%	6.75%	—%
Common Stock Equity	9,713	53.52%	10.20%	5.46%
	$18,148	100.00%		7.68%

Q. What time period does your analyses cover?

A. The capital structure for the Company is measured over the calendar year 2021 test year used in this proceeding using an average of the five quarter-ending balances spanning the 12-month period ending December 31, 2021, based on known and measurable changes through December 31, 2021. Similarly, the costs of the long-term debt and preferred stock are an average of the costs measured for each of the five quarter-ending balances spanning the 12-month calendar 2021 test year, using the Company's actual costs adjusted for known and measurable changes through December 31, 2021.

III. FINANCING OVERVIEW

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

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

As described in the testimony of Mr. Stefan A. Bird, through the Energy Vision 2020 project, PacifiCorp is in the process of repowering its wind generation fleet and significantly increasing its wind generation and transmission capacity. PacifiCorp expects to spend approximately $3.5 billion for investments in renewable energy projects and related transmission through calendar year 2021. This capital spending will require PacifiCorp to raise funds by issuing new long-term debt in the capital markets, retaining earnings, and if needed, obtaining new capital contributions from its parent company, Berkshire Hathaway Energy Company (BHE). This increase in wind generation and transmission capacity will support PacifiCorp's progress towards acquiring the new renewable resources identified in PacifiCorp's 2019 Integrated Resource Plan (IRP) action plan.

Q. How does PacifiCorp finance its electric utility operations?

A. Generally, PacifiCorp finances its regulated utility operations using a mix of debt and common equity capital of approximately 48/52 percent, respectively. During periods of significant capital expenditures, as expected to continue now through calendar year end 2023 for the potential new renewable resources identified in PacifiCorp's 2019 IRP action plan, the Company will need to maintain an average common equity component in excess of 52 percent to maintain its credit rating and finance the debt component of the capital structure at the lowest reasonable cost to customers. Maintaining the Company's credit rating will provide more flexibility on the type and timing of debt financing, better access to capital markets, a more competitive cost of debt, and over the long-run, more stable credit ratings. All of these factors assist in financing expenditures like PacifiCorp's Energy Vision 2020 project and potential new renewable resources identified in PacifiCorp's 2019 IRP action plan. In addition, PacifiCorp needs a greater common equity component to offset various adjustments that rating agencies make to the debt component of the Company's published financial statements and to mitigate the impact the TCJA has had on the

Company's credit metrics. I discuss these adjustments in greater detail later in my testimony.

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

A. As a regulated public utility, PacifiCorp has a duty and an obligation to provide safe, adequate, and reliable service to customers in its Oregon service area while prudently balancing cost and risk. Major capital expenditures are required in the near-term for new plant investment to fulfill its service obligation, including capital expenditures for repowering wind projects, new wind, new transmission, and wildfire mitigation. These capital investments also have associated operating and maintenance costs. As part of its annual business plan process, PacifiCorp reviews all of its estimated cash inflows and outflows to determine the amount, timing, and type of new financing required to support these activities and provide for financial results and credit ratings that balance the cost of capital with continued access to the financial markets.

Q. How does PacifiCorp manage its dividends to BHE?

A. PacifiCorp benefits from its affiliation with BHE as there is no dividend requirement. Historically, PacifiCorp has paid dividends to BHE to manage the common equity component of the capital structure and keep the Company's overall cost of capital at a prudent level. In major capital investment periods, PacifiCorp is able to retain earnings to help finance capital investments and forgo paying dividends to BHE. For example, following BHE's acquisition of PacifiCorp in 2006, PacifiCorp managed the capital structure through the timing and amount of long-term debt issuances and capital contributions from BHE, while forgoing any common dividends for nearly five years. At other times, absent the payment of dividends, retention of earnings could cause the percentage of common equity to grow beyond the level necessary to support the current credit ratings. Accordingly, dividend payments can be necessary, in combination with debt issuances, to maintain the appropriate percentage of equity in PacifiCorp's capital structure. With the increased capital investment required for the Energy Vision 2020 project, wildfire mitigation projects and other capital expenditures, however, the proposed capital structure in this case anticipates no additional common dividend payments by PacifiCorp to BHE through calendar year 2020 and $375 million in 2021.

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

A. PacifiCorp has completed the majority of its recent long-term financing using secured first mortgage bonds issued under the Mortgage Indenture dated January 9, 1989. Exhibit PAC/301, Pro forma Cost of Long-Term Debt, shows that, over the test period, PacifiCorp is projected to have an average of approximately $8.2 billion of first mortgage bonds outstanding, with an average cost of 4.85 percent. Presently, all outstanding first mortgage bonds bear interest at fixed rates. Proceeds from the issuance of the first mortgage bonds (and other financing instruments) are used to finance the utility operation.

Another important source of financing in the past has been the tax-exempt financing associated with certain qualifying equipment at power generation plants. Under arrangements with local counties and other tax-exempt entities, these entities issue securities, PacifiCorp borrows the proceeds of these issuances and pledges its credit quality to repay the debt to take advantage of the tax-exempt status of the financing. During the 12 months ending December 31, 2021, PacifiCorp's tax-exempt portfolio is projected to be approximately $218 million, with an average cost of 1.81 percent, including the cost of issuance and remarketing.

Credit Ratings

Q. What are PacifiCorp's current credit ratings?

A. PacifiCorp's current ratings are shown in Table 2.

Table 2: PacifiCorp Credit Ratings

	Moody's	Standard & Poor's
Senior Secured Debt	A1	A+
Senior Unsecured Debt	A3	A
Outlook	Stable	Stable

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

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. Many institutional investors have fiduciary responsibilities to their clients, and are typically not permitted to purchase non-investment grade (*i.e.*, rated below Baa3/BBB-) securities or in some cases even securities rated below a single A. A solid credit rating directly benefits customers by reducing the immediate and future borrowing costs related to the financing needed to support regulatory obligations.

Second, credit ratings are an estimate of the probability of default by the issuer on each rated security. Lower ratings equate to higher risks and higher costs of debt. The Great Recession of 2008-2009 provides a clear and compelling example of the benefits of the Company's credit rating because PacifiCorp was able to issue new long-term debt during the midst of the financial turmoil. Other lower-rated utilities were shut out of the market and could not obtain new capital.

Third, PacifiCorp has a near constant need for short-term liquidity as well as periodic long-term debt issuances. PacifiCorp pays significant amounts daily to suppliers whom we count on to provide necessary goods and services such as fuel, energy, and inventory. Being unable to access funds can risk the successful completion of necessary capital infrastructure projects and would increase the chance of outages and service failures over the long term.

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

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

A. During the Great Recession in 2008, Arizona Public Service Company (rated Baa2/BBB- at that time) filed a letter with the Arizona Corporation Commission in October 2008 stating that the commercial paper market was completely closed to it and it likely could not successfully issue long-term debt.[1]

Further, those issuers who could access the markets paid rates well above the levels that PacifiCorp was able to obtain. For example, PacifiCorp issued new 10-year and 30-year long-term debt in January 2009 with 5.50 percent and 6.00 percent coupon rates, respectively. Subsequently, Puget Sound Energy (rated Baa2/A- at that

[1] *See* Exhibit PAC/302.

time) issued new seven-year debt at a credit spread over Treasuries of 480.3 basis points resulting in a 6.75 percent coupon.

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

A. Yes. Regulated utilities such as PacifiCorp are unique in that they cannot unilaterally set the price for their services. The financial integrity of a regulated utility is largely a result of the prudence of utility operations and the corresponding prices set by regulators. Rates are established by regulators to permit the utility to recover prudently incurred operating expenses and a reasonable opportunity to earn a fair return on the capital invested.

Rating agencies and investors have a keen understanding of the importance of regulatory outcomes. For example, Standard & Poor's (S&P) has opined on the correlation between regulatory outcomes and credit ratings, concluding:

> Although not common, rate case outcomes can sometimes lead directly to a change in our opinion of creditworthiness. Often it's a case that takes on greater importance because of the issues being litigated. For example, in 2010, we downgraded Florida Power & Light and its affiliates following a Florida Public Service Commission rate ruling that attracted attention due to drastic changes to settled practices on rate case particulars like depreciation rates. More recently, in June 2016, we downgraded Central Hudson Electric & Gas due to our revised opinion of regulatory risk. While that reflected the company's own management of regulatory risk, it was prompted in part by other rate case decisions in New York that highlighted the overall risk in the state.[2]

Similarly, Moody's recently issued a credit opinion for PacifiCorp, concluding:

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

[2] S&P Ratings Direct, *Assessing U.S. Investor-Owned Utility Regulatory Environments* (Aug. 10, 2016), at 4.

> ....The ratings could be downgraded if PacifiCorp's capital expenditures are funded in a manner inconsistent with its current financial profile, or if adverse regulatory rulings lower its credit metrics, as demonstrated for example, by a ratio of CFO pre-W/C/Debt sustained below 20%.[3]

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

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

A. PacifiCorp is in the midst of a period of major capital spending and investing in cost-effective infrastructure to provide electric service that is reliable, clean, and affordable. In addition to being cost-effective resources, PacifiCorp's investments in its existing wind fleet and new wind generation and transmission play a critical role in PacifiCorp's ability to meet the energy policy objectives of the state of Oregon on a least-cost, least-risk basis. If PacifiCorp does not have consistent access to the capital markets at reasonable costs, these borrowings and the resulting costs of building new facilities become more expensive than they otherwise would be. The inability to access financial markets can threaten the completion of necessary projects and can impact system reliability and customer safety. Maintaining the current single A credit rating makes it more likely PacifiCorp will have access to the capital markets at reasonable costs even during periods of financial turmoil.

[3] Moody's Credit Opinion, *PacifiCorp Update to Credit Analysis* (June 27, 2019), at 2.

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

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

To determine the savings realized from maintaining a higher credit rating, in Exhibit PAC/303 New Debt Issue Spreads, I compared the actual effective interest rate on the Company's existing long-term debt forecasted to be outstanding during the calendar year 2021 test period, which was issued since its acquisition by BHE in 2006, comprising 14 series of debt, to what the effective interest rate would have been with a BBB credit rating. The issuance spread of each issuance was changed to match what a BBB rated utility achieved at about the same point in time that PacifiCorp issued the debt. The total result for the 14 series of debt averaging $5.5 billion over the test period, would have been an effective average interest rate of approximately 5.42 percent or 52 basis points higher than the actual effective interest rate. Combined with the existing pre-acquisition debt, the resulting overall cost of long-term debt would increase to 5.11 percent if the Company had a BBB rating. PacifiCorp is currently projecting an overall cost of long-term debt of 4.77 percent, or 34 basis points lower than it might have otherwise been under the scenario I described above.

Table 3 below shows the reduction in the Company's cost of long-term debt since 2010.

Table 3: PacifiCorp's Cost of Long-Term Debt

	Dec 2020	UE 263 Dec 2013	UE 246 Dec 2012	UE 217 Dec 2010	UE 210 Dec 2009
Cost of Long-Term Debt	4.77%	5.32%	5.37%	5.85%	5.96%

PacifiCorp's customers have benefited from a 119 basis points (1.19 percent) reduction in the Company's cost of long-term debt. The Company estimates that this reduction in the average cost of debt since 2010 results in a decrease of approximately $24.0 million in the revenue requirement in the current case. Customers have also benefited from the Company's ability to negotiate lower underwriting fees on long-term debt issuances through BHE's global underwriting fee position.

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

A. Yes. Higher-rated companies have greater access to the long-term markets for power purchases and sales. This access provides these companies with more alternatives to meet the current and future load requirements of their customers. Additionally, a company with strong ratings will often avoid having to meet costly collateral requirements that are typically imposed on lower-rated companies when securing power in these markets.

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

Q. Is the proposed capital structure consistent with PacifiCorp's current credit rating?

A. Yes. This capital structure is intended to help the Company deliver its required capital expenditures and achieve financial metrics that will meet rating agency expectations.

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

A. Yes. Although ring-fenced, PacifiCorp's credit ratios have been weak for the ratings level. PacifiCorp has been able to sustain its ratings in part through the acquisition by BHE and its parent, Berkshire Hathaway Inc. S&P was very clear on this point in its March 2019 assessment of PacifiCorp:

> Under our group rating methodology, we consider PacifiCorp to be a core subsidiary of BHE with a group credit profile of 'a'. The core status reflects our view that PacifiCorp is highly unlikely to be sold, has strong long-term commitment from senior management, is successful at what it does, and contributes meaningfully to the group. At the same time, we consider PacifiCorp as potentially insulated, with existing insulation measures that would support a one-notch separation between PacifiCorp and parent BHE. Given its core subsidiary status and BHE's group credit profile of 'a', the issuer credit rating on PacifiCorp is 'A'.[4]

Moody's states in their June 2019 credit opinion of PacifiCorp:

> PacifiCorp benefits from its affiliation with Berkshire Hathaway Inc., which requires no regular dividends from PacifiCorp or BHE. From a credit perspective, the company's ability to retain its earnings as an entity that is privately held, particularly by a deep-pocketed sponsor like Berkshire Hathaway Inc., is an advantage over most other investor owned utilities that are typically held to a regular dividend to their shareholders. PacifiCorp currently pays dividends that are sized to manage its equity ratio (as measured by unadjusted equity to equity plus long term debt) around its allowed levels of slightly higher than 50% (regulations restrict dividends if this ratio falls below 44%). As of December 2018, PacifiCorp reports its actual equity percentage, as calculated under this test, was 54%.

[4] S&P Ratings Direct, *PacifiCorp* (Mar. 15, 2019), at 9.

> Furthermore, BHE has placed PacifiCorp in a ring-fencing structure that restricts dividends if PacifiCorp's ratings fall to non-investment grade.[5]

These examples are evidence of the credit rating benefit resulting from BHE's ownership of PacifiCorp

Q. How does the TCJA impact PacifiCorp's credit rating?

A. The three main rating agencies have issued reports on the impact of tax reform on U.S. utilities and their holding companies and believe that tax reform will be unfavorable to utilities in the near term but with regulatory support for a stronger capital structure, highly rated utilities may retain positive credit ratings. For example, S&P determined:

> The impact could be sharpened or softened by regulators depending on how much they want to lower utility rates immediately instead of using some of the lower revenue requirement from tax reform to allow the utility to retain the cash for infrastructure investment or other expenses. Regulators must also recognize that tax reform is a strain on utility credit quality, and we expect companies to request stronger capital structures and other means to offset some of the negative impact.[6]

The Company has passed through partial benefits related to tax reform and is planning to pass through all of the remaining benefits in its jurisdictions, thus the negative impact to the Company's key credit metric (Moody's CFO pre-W/C/Debt) has not yet been fully realized. Absent regulatory support for a stronger capital structure, however, the Company's cash from operations will likely fall below levels where it can maintain the minimum 20 percent expectation for this credit metric, which could increase the likelihood of a downgrade.

Moody's states in their January 24, 2018 Sector Comment on Tax Reform:

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[5] Moody's Credit Opinion, *PacifiCorp Update to Credit Analysis* (June 27, 2019), at 6.
[6] S&P Ratings Direct, *U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound* (Jan. 24, 2018), at 5.

> Tax reform mainly affects companies that already had limited cushion in their credit profile. The tax reform usually resulted in a further 150-250 bps drop in CFO pre-WC/debt.
>
> Moody's expects that most utilities will attempt to manage any negative financial implications of tax reform through regulatory channels. Corporate financial policies could also change. The actions taken by utilities will be incorporated into our credit analysis on a prospective basis. It is conceivable that some companies will sufficiently defend their credit profiles.
>
> In practice, we believe that most companies will actively manage their cash flow to debt ratios by issuing more equity or obtaining relief by working through regulatory channels.[7]

Q. Has the Commission recognized that the TCJA has had an adverse impact on utility cash flows and credit ratings?

A. Yes. In February 2019, the Commission adopted Staff's memo recommending approval of an application by Avista Corp. (Avista) to issue stock.[8] Staff's memo included the following statements about the TCJA and the importance of maintaining strong credit ratings:

> Staff finds that the Tax Cuts and Jobs Act of 2017 created unanticipated stresses on [Avista's] credit ratings. The requested authorization signals to rating agencies that the Company is committed to the equity portion of its capital structure. However, it is Staff's finding that restoring a notch in credit ratings involves more than just remedying the cause for the downgrade. On December 21, 2018, Moody's stated, "Avista's credit profile reflects its low-risk vertically integrated electric and gas utility business, regulatory uncertainty in WA and the expected negative cash flow impact of tax reform." Authorization herein as recommended by Staff starts the process of addressing rating agency concerns and restoring a positive credit outlook.[9]

[7] Moody's, *Tax Reform is Credit Negative for Sector, But Impact Varies by Company* (Jan. 24, 2018), at 3.
[8] *In the matter of Avista Corp., dba Avista Util., Application for Authorization to Issue 3,500,000 Shares of Common Stock*, Docket No. UF 4308, Order No. 19-067 (Feb. 28, 2019).
[9] *Id.* at Appendix A, p.4.

In July 2019, the Commission approved Avista's application to issue debt securities, adopting Staff's memo stating that, "Raising the Company's credit ratings back up a notch will require hard work and persistence on the part of Avista's finance group as well as a supportive regulatory environment and achieving target metrics."[10]

In January 2019, the Commission adopted Staff's memo recommending approval of Portland General Electric Company's (PGE) application to refresh a revolving credit facility.[11] Staff's memo contained similar observations about the TCJA and credit ratings:

> Of concern to Staff is Moody's approach to the impacts of the [TCJA]. While one might expect lower taxes would be inherently positive news for utilities, Moody's has focused in on cash flow metrics that are stressed by the recent tax reform. Timely refreshment of this credit facility while PGE is under no heavy time or market pressure is consistent with provision for ongoing liquidity in support of current credit ratings. While approval of this Application does not by itself answer all of Moody's concerns regarding tax reform impacts on the utility sector, the proposed replacement credit facility is consistent with prudent financial management by the Company and will likely be seen as credit positive by both Standard and Poor's and Moody's. As the spreads over benchmark interest rates applicable to PGE depend on the level of the Company's credit ratings, this will be an area for the Commission to continue to monitor.[12]

Rating Agency Debt Imputations

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

A. Yes. Rating agencies and financial analysts consider PPAs to be debt-like and will impute debt and related interest when calculating financial ratios. For example, S&P

[10] *In the matter of Avista Corp., dba Avista Util., Application for Authorization to Issue and Sell $600,000,000 of Debt Securities*, Docket No. UF 4313, Order No. 19-249 (July 30, 2019).
[11] *In the matter of Portland Gen. Elec. Co., Request for Authority to Extend the Maturity of an Existing $500 Million Revolving Credit Agreement,* Docket No. UF 4272(3), Order No. 19-025 (Jan. 23, 2019).
[12] *Id.* at Appendix A, p.9.

will adjust PacifiCorp's published financial results and impute debt balances and interest expense resulting from PPAs when assessing creditworthiness. They do so to obtain a more accurate assessment of a Company's financial commitments and fixed payments. S&P Ratings Direct November 19, 2013, details its view of the debt aspects of PPAs and other debt imputations, and is included as Confidential Exhibit PAC/304.

Q. How does this impact PacifiCorp?

A. In its most recent evaluation of PacifiCorp, S&P added approximately $479 million of additional debt and $21 million of related interest expense to the Company's debt and coverage tests for PPAs and other liabilities of the Company that are considered to be debt-like by S&P.

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

A. Negatively. By including the imputed debt resulting from PPAs and these other adjustments, PacifiCorp's capital structure has a lower equity component as a corollary to the higher debt component, lower coverage ratios, and reduced financial flexibility than what might otherwise appear to be the case from a review of the book value capital structure. For example, as shown in Table 4, if one were to apply the total $479 million amount of debt adjustments that S&P most recently made to PacifiCorp's proposed capital structure in this case, the resulting common equity percentage would decline from 53.52 percent to 52.15 percent. The corresponding higher average adjusted debt percentage of 47.85 percent over the test period reflects an adjusted capital structure that approximates the 48/52 percent baseline mix of debt and common equity capital that PacifiCorp targets.

Table 4: Rating Agency Adjusted Capital

	Proposed Cap Structure		Rating Agency Adjustments	Adjusted Cap Structure	
	Book Values	% of Total		Book Values	% of Total
Long-Term Debt	$8,433	46.47%	$479	$8,912	47.85 %
Preferred Stock	2	0.01%	(1)	1	— %
Common Equity	9,713	53.52%	-	9,713	52.15 %
	$18,148	100.00%	$478	$18,626	100.00 %

IV. CAPITAL STRUCTURE DETERMINATION

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

A. The capital structure is based on the actual capital structure at December 31, 2019 and forecasted capital activity, including known and measurable changes, through December 31, 2021. PacifiCorp averaged the five quarter-end capital structures measured beginning at December 31, 2020, and concluding with December 31, 2021, resulting in a capital structure with an equity component of 53.52 percent. 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, 2019, 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, 2019.

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

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

Q. Why is PacifiCorp using capital balances for the 12-month period ending December 31, 2021, rather than the projected capital structure as of the rate effective date?

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

Q. How does the Company's proposed capital structure compare to recent actual capital structures and to the capital structure authorized in PacifiCorp's last general rate case, docket UE 263 (2013 Rate Case)?

A. The capital structures are compared in Table 5 below.

Table 5: Forecast and Actual Capital Structures

PacifiCorp's Comparison of % Capital Structures						
	Dec 31, 2021 Forecast*	Dec 31, 2020 Forecast*	Dec 31, 2019 Actual*	Dec 31, 2018 Actual*	Dec 31, 2017 Actual*	UE 263 Stipulated Capital Structure
Long-Term Debt	46.47%	47.44%	48.36%	47.89%	48.49%	47.6%
Preferred Stock	0.01%	0.01%	0.02%	0.02%	0.02%	0.3%
Common Equity	53.52%	52.55%	51.62%	52.09%	51.49%	52.1%
Totals	100.00%	100.00%	100.00%	100.00%	100.00%	100.0%

*Five quarter-end average % Capital Structure calculated for trailing 12 month period ending

The percentage increase in the common equity component of the capital structure from the actual December 31, 2019 five-quarter average to that projected for the 2021 forecast test period is due to earnings offset by debt issuances and the forgoing of any common dividend payments in 2020. Further, both of the Company's projected capital structures for 2020 and 2021 contain a higher common equity component than what was approved by the Commission in the 2013 Rate Case. As discussed above, PacifiCorp's increased capital investment requirements and ratings pressure caused by the TCJA require PacifiCorp to increase the equity in its capital structure to maintain its current ratings.

V. FINANCING COST CALCULATIONS

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

A. Consistent with my determination of the percentage capital structure discussed previously, I have similarly calculated the embedded costs of debt and preferred stock as an average of the five quarter-end cost calculations spanning the test period, beginning at December 31, 2020, and concluding with December 31, 2021.

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

A. I calculated the cost of debt by issue, based on each debt series' interest rate and net proceeds at the issuance date, to produce a bond yield to maturity for each series of debt outstanding as of each of the five quarter-ending dates spanning the 12-month calendar 2021 test year. It should be noted that in the event a bond was issued to refinance a higher cost bond, the pre-tax premium and unamortized costs, if any, associated with the refinancing were subtracted from the net proceeds of the bonds that were issued. Each bond yield was then multiplied by the principal amount outstanding of each debt issue, resulting in an annualized cost of each debt issue.

Aggregating the annual cost of each debt issue produces the total annualized cost of debt. Dividing the total annualized cost of debt by the total principal amount of debt outstanding produces the weighted average cost for all debt issues. The support for each of these pro-forma weighted average cost of debt calculations as of each of the five quarter-ending dates spanning calendar year 2021 are provided as attachments by the Company in response to Standard Data Request 12. The average of these five annualized cost of debt calculations, as summarized below, is PacifiCorp's embedded cost of long-term debt for this proceeding:

Table 6: 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
12/31/20	$8,517	4.79%	attach SDR 12-2
03/31/21	8,517	4.80%	attach SDR 12-3
06/30/21	8,117	4.86%	attach SDR 12-4
09/30/21	8,517	4.73%	attach SDR 12-5
12/31/21	8,497	4.70%	attach SDR 12-6
5QE Ave	$8,433	4.77%	

Q. Please describe the changes to the amount of outstanding long-term debt between December 31, 2019, and December 31, 2021?

A. Approximately $38 million and $420 million of the Company's variable and fixed rate long-term debt, respectively, will mature during this period and I have therefore repriced or removed this debt when appropriate in the determination of the proposed average cost of debt. Also, as reflected in Exhibit PAC/301, Pro forma Cost of Long-Term Debt, the Company anticipates new fixed rate long-term debt during the period, a 10- and 30-year split term issuance totaling $850 million in 2020 and a 30-year term issuance totaling $400 million in 2021.

Q. Regarding the $850 million of new long-term issuances in 2020, how did you determine the interest rate and resulting cost for this new long-term debt?

A. The Company's current estimated credit spread for 10-year and 30-year debt is 0.75 and 1.03 percent, respectively. The recent forward 10-year and 30-year U.S. Treasury rates for July 2020 are approximately 1.95 and 2.33 percent, respectively. Issuance costs for 10-year and 30-year debt of this type adds approximately 0.08 and 0.05 percent to the all-in cost, respectively. Therefore, as reflected in Exhibit PAC/301, Pro forma Cost of Long-Term Debt, the Company projects a total all-in cost of long-term debt of 2.78 percent and 3.41 percent, respectively, for the projected new 10-year and 30-year long-term debt.

Q. Regarding the $400 million of new long-term issuances in 2021, how did you determine the interest rate and resulting cost for this new long-term debt?

A. The Company's current estimated credit spread for 30-year debt is 1.03 percent and the recent forward 30-year U.S. Treasury rates for July 2021 is approximately 2.37 percent. Issuance costs for 30-year debt of this type adds approximately 0.05 percent to the all-in cost. Therefore, as reflected in Exhibit PAC/301, Pro forma Cost of Long-Term Debt, the Company projects a total all-in cost of long-term debt of 3.45 percent, for the projected new 30-year long-term debt.

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

A. The Company's variable rate long-term debt in this case is in the form of tax-exempt debt. Exhibit PAC/305, Variable Rate Pollution Control Revenue Bonds, shows that, on average, these securities have been trading at approximately 84 percent of the 30-day London Inter Bank Offer Rate (LIBOR) for the period January 2000 through December 2019. Therefore, the Company has applied a factor of 84 percent to the forward 30-day LIBOR rate as of each of the five quarter-ending dates spanning calendar year 2021 and then added the respective credit facility and remarketing fees for each floating rate tax-exempt bond outstanding during the period. Credit facility and remarketing fees are included in the interest component because these are costs which contribute directly to the interest rate on the securities and are charged to interest expense. This method is consistent with the Company's past practices when determining the cost of debt in previous Oregon general rate cases as well as in other states that regulate PacifiCorp.

Q. Did you make any further adjustments in your pro-forma calculations of the Company's weighted cost of debt over the calendar 2021 test period?

A. Yes. For the pro-forma weighted average cost of debt calculations made for each of the five quarter-ending dates spanning calendar year 2021, as evidenced in the attachments provided by the Company in response to Standard Data Request 12, I adjusted the interest rate on the then existing long-term debt scheduled to mature within one year to reflect expected financing rates. This adjustment is consistent with the Commission practice as set forth in Order 01-787[13] and with the Company's practice in cases since that order.

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

A. The embedded cost of preferred stock was calculated by first determining the cost of money for each issue. I began by dividing the annual dividend per share by the per share net proceeds for each series of preferred stock. The resulting cost rate associated with each series was then multiplied by the total par or stated value outstanding for each issue to yield the annualized cost for each issue. The sum of annualized costs for each issue produces the total annual cost for the entire preferred stock portfolio. I then divided the total annual cost by the total amount of preferred stock outstanding to produce the weighted average cost for all issues. The result is PacifiCorp's embedded cost of preferred stock.

Embedded Cost of Long-Term Debt

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

A. The cost of long-term debt is 4.77 percent, as shown in Exhibit PAC/301, Pro forma Cost of Long-Term Debt.

Embedded Cost of Preferred Stock

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

A. Exhibit PAC/306, Cost of Preferred Stock, shows the embedded costs of preferred stock to be 6.75 percent.

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[13] *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).

VI. IMPLEMENTATION OF TCJA TAX BENEFITS IN RATES

Q. How does PacifiCorp propose to include the benefits of the TCJA's lower tax rate in this proceeding?

A. PacifiCorp will include the tax benefits by: (1) embedding the lower tax rate in base rates as discussed in the testimony of Ms. Shelley E. McCoy, (2) including a rate base deduction for unamortized protected EDIT and lowering income tax expense for the annual level of amortization, and (3) returning to customers the tax benefits deferred as of December 31, 2020.

These actions are consistent with the Commission's decisions in docket UM 1917, docket UM 1985, and docket UE 352.[14]

Q. Please quantify the TCJA balances deferred as of December 31, 2020, that will be refunded to customers.

A. The total amount of deferred TCJA tax benefits projected to be available as of December 31, 2020, is $71.7 million. This consists of the deferral of current tax benefits for the calendar year ending December 31, 2020, of $50.6 million and non-protected EDIT of $21.1 million.[15] PacifiCorp's proposal to return this balance to customers and the related revenue requirement impacts is explained in the direct testimony of Ms. McCoy.

[14] *In the matter of PacifiCorp, dba Pacific Power, Application for Approval of Deferred Accounting Related to the Federal Tax Act*, Docket No. UM 1917, Order No. 19-017 (Jan. 18, 2019); *In the matter of PacifiCorp, dba Pacific Power, Application for an Accounting Order and Request for Amortization Related to the Federal Tax Act*, Docket No. UM 1985, Order No. 19-028 (Jan. 29, 2019); *In the matter of PacifiCorp, dba Pacific Power, 2019 Renewable Adjustment Clause*, Docket No. UE 352, Order No. 19-304 (Sept. 16, 2019). *See* Exhibit PAC/1300 for a discussion of the specific treatment of the benefits of the TCJA.
[15] Exhibit PAC/307.

Q. How do the EDIT balances presented in this case differ from the balances provided by PacifiCorp in dockets UM 1985 and UM 1917?

A. Since PacifiCorp filed its applications in dockets UM 1985 and UM 1917, the Company has made two changes of note, as quantified in Exhibit PAC/307.

First, while total EDIT has not changed, PacifiCorp made a correction in the classification between protected and non-protected amounts since the balances were presented in docket UM 1917. The misclassification was identified during the process of extracting non-protected property EDIT balances from the Company's tax fixed asset system so that they can be deferred and returned to customers over a period of time approved by the Commission. The correction resulted in more EDIT classified as protected and less classified as non-protected.

Second, PacifiCorp will be using the Reverse South Georgia Method (RSGM) to amortize protected EDIT, retroactive to January 1, 2018, because the Company's books and underlying records do not contain the necessary vintage account data to use the Average Rate Assumption Method (ARAM) as originally contemplated. The amortization of PacifiCorp's protected EDIT for 2018, 2019, and 2020 is greater under the RSGM as compared to the Company's ARAM projections. Per Order 19-304 in the 2019 Renewable Adjustment Clause, the non-protected EDIT, including the deferred amortization of protected EDIT for 2018, 2019, and 2020, will be used to offset the Oregon-allocated net book value of the undepreciated plant that is replaced as a result of wind repowering.[16]

[16] *See In the matter of PacifiCorp dba Pacific Power's 2019 Renewable Adjustment Clause*, Docket No. UE 352, Order No. 19-304 (Sept. 16, 2019).

The Reverse South Georgia Method

Q. Please explain why PacifiCorp's books and underlying records do not contain the necessary vintage account data to use the ARAM.

A. For some assets and in certain circumstances, PacifiCorp records situs book depreciation on system-allocated assets. For background, PacifiCorp depreciates system-allocated assets using a base composite life; this base level of book depreciation is system-allocated. An incremental amount of book depreciation is calculated for jurisdictions that approve a composite life different from the base or otherwise approve accelerated book depreciation for system-allocated assets; this incremental amount of book depreciation is situs allocated.

To use the ARAM, book depreciation is required at a jurisdictional level by vintage and tax class to have the necessary vintage account data. Because book depreciation is not maintained at this level for book accounting purposes, PacifiCorp relies on its tax fixed asset system to produce the necessary vintage account data for tax purposes by performing a procedure to allocate book depreciation.

As presently configured, the book depreciation allocation procedure cannot process situs book depreciation on system-allocated assets in a manner that impacts only the vintage account data of the jurisdiction to which the situs book depreciation inures. As a result, the situs book depreciation must be accounted for separately as a tax class of its own, thereby rendering the jurisdictional vintage account data to which the EDIT is actually attached incomplete for the purposes of using the ARAM.

Q. How are the issues with situs book depreciation addressed by the RSGM?

A. Unlike the ARAM, book depreciation is not required at the jurisdictional level by vintage and tax class for amortization of EDIT when using the RSGM. The RSGM requires only the use of a remaining regulatory life for an asset or group of assets to amortize the EDIT on a straight-line basis.

To implement the RSGM, PacifiCorp categorized Oregon-allocated protected EDIT at the level of detail presented in the Company's most recently filed depreciation study. The protected EDIT is then amortized straight-line over Oregon's approved remaining regulatory life for each respective asset or group of assets. For tax years 2018 to 2020, the remaining lives are based on Oregon's most recently approved depreciation study. Beginning in 2021, the remaining lives will be updated to match those approved in the presently pending depreciation study and then again for each depreciation study approved thereafter. If the Commission approves regulatory lives different from those proposed by the Company in this case and the ongoing depreciation study, the protected EDIT amortization included in this case will need to be updated accordingly.

Q. Do PacifiCorp's facts meet the statutory requirements for using the RSGM?

A. Yes. Although there are uncertainties with respect to the proper application of section 13001(d) of the TCJA, PacifiCorp has carefully considered this matter and, based on its facts and circumstances, believes that the use of the RSGM is permitted as a normalization method of accounting.

Q. Does the Internal Revenue Service (IRS) recognize the need for clarity with regard to the EDIT normalization requirements in light of the TCJA?

A. Yes. In Notice 2019-33, the IRS announced its intent to issue guidance to clarify the EDIT normalization requirements, which may include guidance on the use of the RSGM; the Company anticipates this guidance will be issued in 2020. In comments submitted in response to Notice 2019-33, the Edison Electric Institute has requested that the IRS issue transitional guidance that allows taxpayers to correct potential normalization violations on a prospective basis and that the violations be forgiven without penalty. If uncertainties still exist after the guidance is issued, the Company will evaluate the need to file a private letter ruling request.

VII. PENSION COSTS

Q. Please describe the status of PacifiCorp's defined benefit pension plans.

A. To reduce the risk profile of its defined benefit pension plans, PacifiCorp has over time, shifted the accrual of new benefits to its defined contribution 401(k) plan. All non-represented employees hired after January 1, 2008 and all represented employees hired after June 30, 2013, receive retirement benefits solely through the 401(k) plan. Retirement plan benefits for represented employees are determined through the collective bargaining process through which the Company has maintained its focus on shifting to providing benefits through its 401(k) plan. The Company provided non-represented employees hired before January 1, 2008, the ability to receive their retirement through either the pension plan or the 401(k) plan. This choice was offered in 2008, and 41 percent of the eligible participants migrated to the 401(k) plan. The remaining non-represented employees in the defined benefit pension plan continued to receive benefit accruals until accruals were frozen December 31, 2016.

Q. Does this case reflect costs associated with PacifiCorp's defined benefit pension plans?

A. Yes. The Company still incurs net periodic benefit costs for its defined benefit pension plans. The Company's net periodic benefit costs generally include interest costs associated with discounting the projected benefit obligation and amortization of net unrecognized gains and losses, offset by the expected return on plan investments. The level of these costs will be driven by various assumptions including the interest rate used to discount the liability, life expectancy and other demographics of the Company's plan participants, and the expected long-term rate of return based on the mix of investments. This filing reflects pension costs of $8.8 million, including a projected settlement loss of approximately $11.9 million during the 2021 test period.

Q. What is a settlement loss?

A. Accounting guidance provides for delayed recognition of certain gains and losses. These unrecognized costs include an accumulation of past actuarial gains and losses that result from changes in actuarial assumptions, such as the discount rate, and the difference between expected and actual experience, for example asset returns that exceed or underperform the level assumed in determining net periodic benefit cost. Under the Financial Accounting Standards Board's Accounting Standards Codification (ACS) 715, Compensation - Retirement Benefits[17] and ASC 980, Regulated Operations, the majority of the Company's unrecognized net loss is

[17] Formerly known as "FAS 87."

currently amortized over approximately 21 years, which represents the average remaining life expectancy of plan participants. A settlement loss occurs when the aggregate lump sum cash distributions in a calendar year exceed a defined threshold (service cost plus interest cost), requiring under ASC 715 immediate recognition in earnings of a portion of the unrecognized actuarial gains or losses. If not for this requirement, such portion of the net actuarial loss would eventually flow through expense as part of the ongoing amortization over the approximately 21-year period.

Q. Why are actuarial gains and losses an important component of on-going pension expense under ASC 715?

A. Actuarial gains and losses arise annually as remeasurement occurs each year-end under ASC 715 due to changes in assumptions, differences between expected and actual asset returns, actuarial experience, etc. As of December 31, 2019, the Company had $422 million of unrecognized net actuarial losses recorded as a regulatory asset that will generally be recognized to expense over the average remaining life of plan participants (currently approximately 21 years), making it a significant portion of the Company's annual pension expense. Recognition of actuarial gains and losses are amortized over time rather than in the year they occur, which can help minimize volatility in expense from year to year. However, as I described above, settlement accounting under ASC 715 can trigger accelerated recognition of a portion of the unrecognized net actuarial losses. The Company last recognized a settlement loss in 2018 on a total-company basis of $22 million, approximately $6 million of which was Oregon's share. In docket UM 1992, the Company requested approval of deferred accounting treatment related to this settlement loss. However, the Commission denied the application as "a higher number of retirees taking lump sum distributions may be viewed as being a reasonably possible outcome resulting from PacifiCorp's business decisions. It falls within the range of reasonably foreseeable possible outcomes in the then-existing environment of low service costs, stable interest rates and low inflation...[.]"[18]

Q. Does the Company anticipate that settlement losses under ASC 715 will be triggered during the next few years and if so, what is the driver?

A. Yes. Recent history demonstrates that during periods of low interest rates, a higher percentage of participants elect lump sum distributions. Thus, with the very low interest rate environment present at the time the Company's projections for this filing were compiled and the knowledge of what the Company experienced in 2018 when interest rates were similarly low, the Company anticipates that additional settlement losses will occur. Based on actuarial projections, settlement losses of $18.5 million and $11.9 million are forecast during 2020 and 2021, respectively, justifying the inclusion of these costs in base rates.

In periods of low interest rates, the Company experiences lower interest cost on the benefit obligation, which keeps the threshold for determining settlement accounting at a low level. Table 7 below shows the settlement threshold for the last seven years along with the projections for 2020 and 2021. The declining threshold is primarily driven by the low interest rate environment. The Company is likely to be subject to a settlement charge each year that interest rates are sufficiently low.

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[18] *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 1992, Order No. 20-004, at 8 (Jan. 8, 2020).

Table 7: Recent History and Projections of Settlement Threshold ($ in millions)

	2013	2014	2015	2016	2017	2018	2019	2020	Projected 2021
Service cost	$ 5.9	$ 5.3	$ 4.7	$ 4.1	$ —	$ —	$ —	$ —	$ —
Interest cost	$ 51.9	$ 54.0	$ 50.6	$ 51.8	$ 47.3	$ 41.1	$ 42.6	$ 34.4	$ 31.9
Settlement threshold (service cost + interest cost)	$ 57.8	$ 59.3	$ 55.3	$ 55.9	$ 47.3	$ 41.1	$ 42.6	$ 34.4	$ 31.9

In addition to a low settlement threshold, the Company has made assumptions about the number of participants who will take lump sum distributions upon retirement along with their estimated payout. For purposes of valuing the pension benefit obligation, the Company's actuaries generally assume (based on historical experience) that 60 percent of participants will elect lump sum distributions. However, in performing the annual remeasurement of the pension benefit obligation at December 31, 2019, the Company's actuaries assumed 80 percent of participants would elect lump sum distributions in 2020 in anticipation of an increase in the percentage of retiring participants electing lump sums due to the unprecedentedly low interest rates. For 2021, 60 percent of participants are assumed to elect lump sum distributions. In any given year, the actual percentage of participants electing lump sum distributions will differ from what was assumed.

Table 8 below shows the historical number of participants electing lump sums distributions and the resulting value paid out of the plan along with the projections for 2020 and 2021. Table 8 also presents the percentage of participants electing lump sum distributions with 2018, the year in which the Company incurred a $22 million settlement loss, being an outlier at over 73 percent.

Table 8: Historical and Projected Lump Sum Distribution Information ($ in millions)

	2013	2014	2015	2016	2017	2018	2019	Projected 2020	Projected 2021
Lump Sum Distributions	$ 52.2	$ 22.0	$ 40.5	$ 31.9	$ 40.0	$ 52.3	$ 22.7	$ 50.8	$ 34.4
Distributions in Excess of Threshold	$ —	$ —	$ —	$ —	$ —	$ 11.2	$ —	$ 16.4	$ 2.5
Discount Rate	4.05%	4.80%	4.00%	4.40%	4.05%	3.60%	4.25%	3.25%	3.25%
Minimum Present Value Segment Rates(1)	1.02% 3.71% 4.67%	1.40% 4.66% 5.62%	1.40% 3.98% 5.04%	1.69% 4.11% 5.07%	1.47% 3.34% 4.30%	1.96% 3.58% 4.35%	3.21% 4.26% 4.55%	2.13% 3.07% 3.65%	2.04% 3.09% 3.68%
Number of Participants Electing Lump Sums	204	150	216	224	205	211	114	231	172
Percentage of Participants Electing Lump Sums	66.3%	50.2%	64.9%	68.7%	58.4%	73.3%	67.1%	80%	60%

(1) Other than for 2021, represents the IRS's published minimum present value segment rates from September of the preceding year, which are used to value lump sum distributions taken in the subsequent year, in accordance with the Company's pension plan document. For example, the 2.13%/3.07%/3.65% presented under 2020 are the September 2019 rates applicable to lump sum distributions to be taken in 2020. Rates included for 2021 are based on the November 2019 rates published by the IRS, which were the most recently available at the time the projections were compiled. The December 2019 rates were 2.03%/3.06%/3.59%.

As of December 31, 2019, interest rates decreased significantly, resulting in a 3.25 percent discount rate used to perform the annual remeasurement of the Company's benefit obligation and determine the interest cost component of the Company's net periodic benefit cost for 2020. This compares to a 4.25 percent discount rate at December 31, 2018. As presented in Table 7, this decrease results in lower interest cost and thus a lower settlement loss threshold. As presented in Table 8, the applicable minimum present value segment rates for 2020 lump sum distributions are very low; thus, the Company projects higher lump sum distributions and the triggering of a settlement loss in 2020 of an estimated $18.5 million. Based on the current low interest rate environment, the Company projects a settlement loss of $11.9 million in 2021 using the assumptions presented in Table 8. When similar circumstances were present in 2018, the Company incurred a settlement loss of $22 million.

VIII. CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. I respectfully request the Commission adopt PacifiCorp's proposed capital structure with a common equity level of 53.52 percent. This capital structure balances the financial integrity of the Company and costs to customers by reflecting the minimum equity ratio necessary for PacifiCorp to maintain its ratings under current market conditions, especially given the passage of the TCJA. When combined with PacifiCorp's updated cost of long-term debt of 4.77 percent and the cost of equity of 10.20 percent recommended by Ms. Bulkley, this produces a reasonable overall cost of capital of 7.68 percent.

In addition, the Commission should acknowledge the reasonableness of PacifiCorp's treatment of its TCJA tax benefits in rates, and approve PacifiCorp's projected pension costs included in this case.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/301
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Pro forma Cost of Long-Term Debt

February 2020

PACIFICORP
Electric Operations
Pro forma Ave Cost of Long-Term Debt Summary
12 months ended December 31, 2021

LINE NO.	DESCRIPTION	AMOUNT 5QE AVE OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	INTEREST RATE	ALL-IN COST	ORIG LIFE	LINE NO.
1										1
2	**Total First Mortgage Bonds**	**$8,215,000,000**	**($84,778,927)**	**($18,223,151)**	**$8,111,997,921**	**$398,431,858**	**4.750%**	**4.850%**	**25.6**	2
3										3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	$193,750,000	($4,953,665)	($2,181,869)	$186,614,466	$3,525,767	1.660%	1.820%	30.0	4
5	Subtotal - Pollution Control Revenue Bonds	$24,400,000	($225,000)	($428,469)	$23,746,531	$426,512	1.633%	1.748%	29.9	5
6	**Total Pollution Control Revenue Bonds**	**$218,150,000**	**($5,178,665)**	**($2,610,338)**	**$210,360,997**	**$3,952,279**	**1.657%**	**1.812%**	**29.9**	6
7										7
8	Loss on Long Term Debt Reacquistions, without Refunding					$205,126				8
9	**Total Cost of Long Term Debt**	**$8,433,150,000**	**($89,957,593)**	**($20,833,489)**	**$8,322,358,918**	**$402,589,263**	**4.670%**	**4.774%**	**25.7**	9
10										10

PACIFICORP
Electric Operations
Pro forma Ave Cost of Long-Term Debt Summary
12 months ended December 31, 2021

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT 5QE AVE OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1														1
2														2
3	2.950%	Series due Feb 2022	01/06/12	02/01/22	10	$350,000,000	$70,000,000	($546,470)	$0	$69,453,530	$99.219	3.040%	$2,128,000	3
4	2.950%	Series due Feb 2022 (2)	03/06/12	02/01/22	10	$100,000,000	$20,000,000	($34,626)	($994,159)	$18,971,216	$94.856	3.571%	$714,200	4
5	2.950%	Series due Jun 2023	06/06/13	06/01/23	10	$300,000,000	$300,000,000	($2,759,352)	$0	$297,240,648	$99.080	3.058%	$9,174,000	5
6	3.600%	Series due Apr 2024	03/13/14	04/01/24	10	$425,000,000	$425,000,000	($3,600,164)	($1,943,075)	$419,456,761	$98.696	3.757%	$15,967,250	6
7	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	7
8	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	8
9	2.695%	Proforma Series#1	07/16/20	07/16/30	10	$400,000,000	$400,000,000	($2,816,376)	$0	$397,183,624	$99.296	2.776%	$11,104,000	9
10	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	$98.766	7.807%	$23,421,000	10
11	5.900%	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	11
12	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	12
13	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	13
14	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	14
15	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	15
16	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	16
17	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	17
18	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	18
19	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	19
20	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	20
21	3.358%	Proforma Series#2	07/16/20	07/16/50	30	$450,000,000	$450,000,000	($4,068,424)	$0	$445,931,576	$99.096	3.406%	$15,327,000	21
22	3.397%	Proforma Series#3	07/16/21	07/16/51	30	$400,000,000	$160,000,000	($1,510,080)	$0	$158,489,920	$99.056	3.448%	$5,516,800	22
23	3.432%	Series - Cur Mat LT Debt (repriced)			30		$591,400,000	($5,438,083)	$0	$585,961,917	$99.080	3.482%	$20,591,090	23
24	**4.637%**	**Subtotal - Bullet FMBs**			**25**		**$7,866,400,000**	**($81,855,037)**	**($4,233,228)**	**$7,780,311,735**		**4.722%**	**$371,459,340**	24
25														25
26	8.260%	Series C due Jan 2022	01/08/92	01/07/22	30	$5,000,000	$1,000,000	($6,649)	($136,928)	$856,423	$85.642	9.745%	$97,450	26
27	8.270%	Series C due Jan 2022	01/09/92	01/10/22	30	$4,000,000	$800,000	($6,119)	($109,542)	$684,339	$85.542	9.768%	$78,144	27
28	**8.264%**	**Subtotal - Series C MTNs**			**30**		**$1,800,000**	**($12,767)**	**($246,471)**	**$1,540,762**		**9.755%**	**$175,594**	28
29														29
30	8.050%	Series E due Sep 2022	09/18/92	09/01/22	30	$15,000,000	$9,000,000	($78,883)	($1,017,340)	$7,903,778	$87.820	9.257%	$833,130	30
31	8.070%	Series E due Sep 2022	09/09/92	09/09/22	30	$8,000,000	$4,800,000	($42,071)	($542,581)	$4,215,348	$87.820	9.280%	$445,440	31
32	8.110%	Series E due Sep 2022	09/11/92	09/09/22	30	$12,000,000	$7,200,000	($63,106)	($813,872)	$6,323,022	$87.820	9.325%	$671,400	32
33	8.120%	Series E due Sep 2022	09/11/92	09/09/22	30	$50,000,000	$30,000,000	($262,943)	($3,391,132)	$26,345,925	$87.820	9.336%	$2,800,800	33
34	8.050%	Series E due Sep 2022	09/14/92	09/14/22	30	$10,000,000	$6,000,000	($52,589)	($678,226)	$5,269,185	$87.820	9.258%	$555,480	34
35	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	$25,000,000	$20,000,000	($160,152)	($1,649,302)	$18,190,546	$90.953	8.953%	$1,790,600	35
36	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	$26,000,000	$20,800,000	($166,558)	($2,351,185)	$18,282,257	$87.895	9.283%	$1,930,864	36
37	8.230%	Series E due Jan 2023	01/29/93	01/20/23	30	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	$99.056	8.316%	$332,640	37
38	8.230%	Series E due Jan 2023	01/20/93	01/20/23	30	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	$92.525	8.951%	$447,550	38
39	**8.101%**	**Subtotal - Series E MTNs**			**30**		**$106,800,000**	**($812,987)**	**($10,868,470)**	**$95,118,544**		**9.183%**	**$9,807,904**	39
40														40
41	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	$93.730	7.804%	$858,440	41
42	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	$27,000,000	$27,000,000	($246,981)	($1,445,880)	$25,307,139	$93.730	7.804%	$2,107,080	42
43	7.230%	Series F due Aug 2023	08/16/93	08/16/23	30	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	$97.294	7.457%	$1,118,550	43
44	7.240%	Series F due Aug 2023	08/16/93	08/16/23	30	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	$97.294	7.467%	$2,240,100	44
45	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.810%	$136,200	45
46	6.720%	Series F due Sep 2023	09/14/93	09/14/23	30	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.780%	$135,600	46
47	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	$98.552	6.865%	$343,250	47
48	6.750%	Series F due Oct 2023	10/26/93	10/26/23	30	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	$99.238	6.810%	$817,200	48
49	6.750%	Series F due Oct 2023	10/26/93	10/26/23	30	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	$99.238	6.810%	$1,089,600	49
50	6.750%	Series F due Oct 2023	10/26/93	10/26/23	30	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	$99.238	6.810%	$1,362,000	50
51	**7.044%**	**Subtotal - Series F MTNs**			**30**		**$140,000,000**	**($1,193,670)**	**($2,874,983)**	**$135,931,347**		**7.291%**	**$10,208,020**	51
52														52
53	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	53
54	**6.710%**	**Subtotal - Series G MTNs**			**30**		**$100,000,000**	**($904,467)**	**$0**	**$99,095,533**		**6.781%**	**$6,781,000**	54
55														55

PACIFICORP
Electric Operations
Pro forma Ave Cost of Long-Term Debt Summary
12 months ended December 31, 2021

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT 5QE AVE OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
56	**4.750%**	**Total First Mortgage Bonds**			**26**		**$8,215,000,000**	**($84,778,927)**	**($18,223,151)**	**$8,111,997,921**		**4.850%**	**$398,431,858**	56
57														57
58														58
59	1.664%	Converse 94 due Nov 2024	11/17/94	11/01/24	30	$8,190,000	$8,190,000	($209,778)	($86,323)	$7,893,899	$96.385	1.821%	$149,140	59
60	1.631%	Emery 94 due Nov 2024	11/17/94	11/01/24	30	$121,940,000	$121,940,000	($3,274,246)	($1,925,767)	$116,739,987	$95.736	1.816%	$2,214,430	60
61	1.773%	Lincoln 94 due Nov 2024	11/17/94	11/01/24	30	$15,060,000	$15,060,000	($422,858)	($81,427)	$14,555,715	$96.651	1.920%	$289,152	61
62	1.698%	Sweetwater 94 due Nov 2024	11/17/94	11/01/24	30	$21,260,000	$21,260,000	($510,479)	($88,352)	$20,661,169	$97.183	1.820%	$386,932	62
63	1.614%	Converse 95 due Nov 2025	11/17/95	11/01/25	30	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	$97.509	1.721%	$91,213	63
64	1.716%	Lincoln 95 due Nov 2025	11/17/95	11/01/25	30	$22,000,000	$22,000,000	($404,262)	$0	$21,595,738	$98.162	1.795%	$394,900	64
65	**1.660%**	**Subtotal - Secured PCRBs**			**30**		**$193,750,000**	**($4,953,665)**	**($2,181,869)**	**$186,614,466**		**1.820%**	**$3,525,767**	65
66														66
67	1.633%	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	1.748%	$426,512	67
68	**1.633%**	**Subtotal - Unsecured PCRBs**			**30**		**$24,400,000**	**($225,000)**	**($428,469)**	**$23,746,531**		**1.748%**	**$426,512**	68
69														69
70	**1.657%**	**Total PCRB Obligations**			**30**		**$218,150,000**	**($5,178,665)**	**($2,610,338)**	**$210,360,997**		**1.812%**	**$3,952,279**	70
71														71
72			**REACQ**	**ORG MAT**										72
73			**DATE**	**DATE**										73
74		8.375% Series A QUIDS	11/17/00	06/30/35									$107,887	74
75		8.55% Series B QUIDS	11/17/00	12/31/25									$84,084	75
76		Carbon '94 PCRB Series	02/18/16	11/01/24									$13,155	76
77		**Long-Term Debt Reacquisition, without refunding amortization**											**$205,126**	77
78														78
79	**4.670%**	**Total Long-Term Debt**			**26**		**$8,433,150,000**	**($89,957,593)**	**($20,833,489)**	**$8,322,358,918**		**4.774%**	**$402,589,263**	79
80														80

Exhibit PAC/301
Kobliha/3

Docket No. UE 374
Exhibit PAC/302
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Arizona Public Service Company October 2008 Letter to the Arizona Corporation Commission

February 2020

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LAW DEPARTMENT

Thomas L. Mumaw
Senior Attorney
(602) 250-2052
Direct Line

October 17, 2008

Arizona Corporation Commission
DOCKETED
OCT 17 2008
DOCKETED BY

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 8th 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.[1] 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

[1] Borrowing on bank lines of credit is normally 25 to 50 basis points more expensive than commercial paper.

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.

Geo*Smart* 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") GEO*Smart* 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 Geo*Smart* program. In recent conversations, EGIA informed APS that a number of financial institutions have been identified that **may** be able to provide funding for GEO*Smart*. APS remains hopeful but cannot offer any assurance that EGIA will secure other financial backing in the future.

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.[2] 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.[3]

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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[2] 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.

[3] 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.

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

Thomas L. Mumaw

Attorney for Arizona Public
Service Company

Attachments

cc: Mike Gleason, Chairman
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Jeff Hatch-Miller
Gary Pierce
Brian McNeil
Ernest Johnson
Lyn A. Farmer
Janet Wagner
Rebecca Wilder
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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

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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.

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 27th to October 1st – 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

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 374
Exhibit PAC/303
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

New Debt Issue Spreads

February 2020

PACIFICORP
Electric Operations
Pro FormaCost of Long-Term Debt Detail
12 months ended December 31, 2021

LINE NO.	INTEREST RATE (a)	DESCRIPTION (b)	PRINCIPAL AMOUNT ORIGINAL ISSUE (g)	PRINCIPAL AMOUNT AVE OUTSTANDING (h)	ISSUANCE EXPENSES (1) (i)	REDEMPTION EXPENSES (j)	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT (k)	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT (l)	MONEY TO COMPANY (m)	ANNUAL DEBT SERVICE COST (n)	LINE NO.
79	4.670%	**Total Long-Term Debt**		$8,433,150,000	($89,957,593)	($20,833,489)	$8,322,358,918		4.774%	$402,589,263	79
	4.689%	**Actual Post Acquistion Debt Issuances** (1)		$5,465,000,000	($60,038,631)	($6,913,867)	$5,398,047,502		4.89%	$267,404,450	
	5.228%	**Pro Forma Post Acquistion Debt Issuances**		$5,465,000,000	($53,649,631)	($6,913,867)	$5,404,436,502		5.42%	$296,027,700	
	5.019%	**Total Long-Term Debt - Pro Forma**		$8,433,150,000	($83,568,593)	($20,833,489)	$8,328,747,918		5.113%	$431,212,513	

(1) Issuance Expenses include issuance yield discounts

REDACTED
Docket No. UE 374
Exhibit PAC/304
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Nikki l. Kobliha

S&P Ratings Direct November 19, 2013

February 2020

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

Docket No. UE 374
Exhibit PAC/305
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Indicative Forward PCRB Variable Rates

February 2020

Indicative Forward PCRB Variable Rates
For Quarter End Periods for Year Ending December 31, 2021

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)

	Forward 30 Day LIBOR* (1)	Historical Floating Rate PCRB / 30 Day LIBOR (2)	Forecast Floating Rate PCRB (1) * (2)
12/31/2020	1.62%	84%	1.363%
3/31/2021	1.57%	84%	1.317%
6/30/2021	1.57%	84%	1.317%
9/30/2021	1.56%	84%	1.311%
12/31/2021	1.63%	84%	1.366%
5QE Ave			1.335%

* Source: Bloomberg L.P. (12/17/19)

Docket No. UE 374
Exhibit PAC/306
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Cost of Preferred Stock

February 2020

PACIFICORP
Electric Operations
Cost of Preferred Stock
12 Months Ended December 31, 2021

Line No.	Description of Issue	Issuance Date	Call Price	Annual Dividend Rate	Shares O/S	Total Par or Stated Value O/S	Net Premium & (Expense)	Net Proceeds to Company	% of Gross Proceeds	Cost of Money	Annual Cost	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	
1	**Serial Preferred, $100 Par Value**											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	**Total Cost of Preferred Stock**			**6.753%**	**23,976**	**$2,397,600**	**$0**	**$2,397,600**		**6.753%**	**$161,902**	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 374
Exhibit PAC/307
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Changes in EDIT Balances

February 2020

PACIFICORP

Deferred Current Tax Benefits, including Interest			(50,643,669)
Deferred Non-Protected EDIT, plus Gross-Up	A (15,884,525)	(5,178,741)	(21,063,266)
Total Deferred Tax Benefits			**(71,706,935)**

Projection of Deferred Current Tax Benefits

Month	Beginning Balance	Accrue 2020 Deferral	Amortize 2019 Deferral	Accrue Interest	Ending Balance
January 2020	(50,953,898)	(3,894,508)	4,018,879	(303,346)	(51,132,873)
February 2020	(51,132,873)	(3,894,508)	4,018,879	(140,898)	(51,149,400)
March 2020	(51,149,400)	(3,894,508)	4,018,879	(128,812)	(51,153,841)
April 2020	(51,153,841)	(3,894,508)	4,018,879	(116,688)	(51,146,158)
May 2020	(51,146,158)	(3,894,508)	4,018,879	(104,526)	(51,126,313)
June 2020	(51,126,313)	(3,894,508)	4,018,879	(92,326)	(51,094,268)
July 2020	(51,094,268)	(3,894,508)	4,018,879	(80,089)	(51,049,986)
August 2020	(51,049,986)	(3,894,508)	4,018,879	(67,813)	(50,993,428)
September 2020	(50,993,428)	(3,894,508)	4,018,879	(55,499)	(50,924,556)
October 2020	(50,924,556)	(3,894,508)	4,018,879	(43,146)	(50,843,331)
November 2020	(50,843,331)	(3,894,508)	4,018,879	(30,755)	(50,749,715)
December 2020	(50,749,715)	(3,894,508)	4,018,879	(18,325)	(50,643,669)
Total		**(46,734,096)**	**48,226,548**	**(1,182,223)**	

Reconciliation of EDIT Balances

	Property			Def. Amort. Of	
Item	**Protected**	**Non-Protected**	**Non-Property**	**Protected Property**	**Total**
Oregon EDIT @ 01/01/2018: UM-1917	**(323,605,791)**	**(93,279,909)**	**(11,891,678)**	**0**	**(428,777,378)**
Classification Correction	(17,868,147)	17,868,147	0	0	**0**
Oregon EDIT @ 01/01/2018: FINAL	**(341,473,938)**	**(75,411,762)**	**(11,891,678)**	**0**	**(428,777,378)**
Deferred Amort. of Protected EDIT: 2018	15,702,122	0	0	(15,702,122)	**0**
Deferred Amort. of Protected EDIT: 2019	16,981,193	0	0	(16,981,193)	**0**
Deferred Amort. of Protected EDIT: 2020	16,855,705	0	0	(16,855,705)	**0**
Oregon EDIT @ 12/31/2020 before RAC Adj.	**(291,934,918)**	**(75,411,762)**	**(11,891,678)**	**(49,539,020)**	**(428,777,378)**
RAC Adjustment - Actual 2019	0	75,411,762	11,891,678	3,216,436	**90,519,876**
RAC Adjustment - Projected 2020	0	0	0	30,438,059	**30,438,059**
Oregon EDIT @ 12/31/2020	**(291,934,918)**	**0**	**0**	**(15,884,525)** A	**(307,819,443)**

Comparison of Protected EDIT Amortization: RSGM v ARAM

Item	RSGM	UM 1917: ARAM	Difference
Protected EDIT Amortization 12/31/2018	(15,702,122)	(7,876,607)	(7,825,515)
Protected EDIT Amortization 12/31/2019	(16,981,193)	(7,494,833)	(9,486,360)
Protected EDIT Amortization 12/31/2020	(16,855,705)	(7,480,170)	(9,375,535)
Total	**(49,539,020)**	**(22,851,610)**	**(26,687,410)**

Docket No. UE 374
Exhibit PAC/400
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Ann E. Bulkley

February 2020

TABLE OF CONTENTS

ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. What is your position with Concentric Energy Advisors, Inc. (Concentric)?

A. I am employed by Concentric as a Senior Vice President.

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

A. I am submitting this direct testimony before the Public Utility Commission of Oregon (Commission) on behalf of PacifiCorp, which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company (BHE).

Q. Please describe your education and experience.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with more than 20 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues, with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have included my resume, a description of Concentric's energy and utility practice, and a summary of testimony that I have filed in other proceedings as Exhibit PAC/401 to this testimony.

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

A. Yes. A list of proceedings in which I have provided testimony is provided in Exhibit PAC/401 to this testimony.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the appropriate Return on Equity (ROE)[1] for PacifiCorp's electric utility operations in Oregon and to provide an assessment of its proposed capital structure to be used for ratemaking purposes. A summary of my ROE analyses results is provided in Exhibit PAC/402. My analyses and recommendations are supported by the data presented in Exhibit PAC/403 through Exhibit PAC/413, which were prepared by me or under my direction.

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

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

[1] Throughout my direct testimony, I interchangeably use the terms "ROE" and "cost of equity".

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

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

A. Section III provides a summary of my analyses and conclusions. Section IV reviews the regulatory guidelines pertinent to the development of the cost of capital. Section V discusses current and projected capital market conditions and the effect of those conditions on PacifiCorp's cost of equity in Oregon. Section VI explains my selection of a proxy group of electric utilities. Section VII describes my analyses and the analytical basis for the recommendation of the appropriate ROE for PacifiCorp. Section VIII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for PacifiCorp in this case. Section IX assesses the proposed capital structure of PacifiCorp as compared with the capital structures of the utility operating subsidiaries of the proxy group companies. Section X presents my conclusions and recommendations for the market cost of equity.

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[2] The selection and purpose of developing a group of comparable companies is discussed in detail in Section VI of my direct testimony.

III. SUMMARY OF ANALYSES AND CONCLUSIONS

Q. What is your recommended ROE for PacifiCorp?

A. Based on the analytical results presented in Figure 1 below, I believe a range from 9.75 percent to 10.25 percent is reasonable. Within that range, a return of 10.20 percent is reasonable. This recommendation reflects the range of results for the proxy group companies, the relative business, financial, and regulatory risk of PacifiCorp's electric operations in Oregon as compared to the proxy group, and current capital market conditions.

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

A. In developing my recommended ROE for PacifiCorp, I considered the following:

- The *Hope* and *Bluefield* decisions[3] that established the standards for determining a fair and reasonable allowed ROE, including consistency of the allowed return with other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and that the end result must lead to just and reasonable rates.
- The effect of current and projected capital market conditions on investors' return requirements.
- The results of several analytical approaches that provide estimates of PacifiCorp's cost of equity.
- PacifiCorp's regulatory, business, and financial risks relative to the proxy group of comparable companies and the implications of those risks.

Q. Please explain how you considered those factors.

A. I relied on several analytical approaches to estimate PacifiCorp's cost of equity based on a proxy group of publicly-traded companies. As shown in Figure 1, those ROE

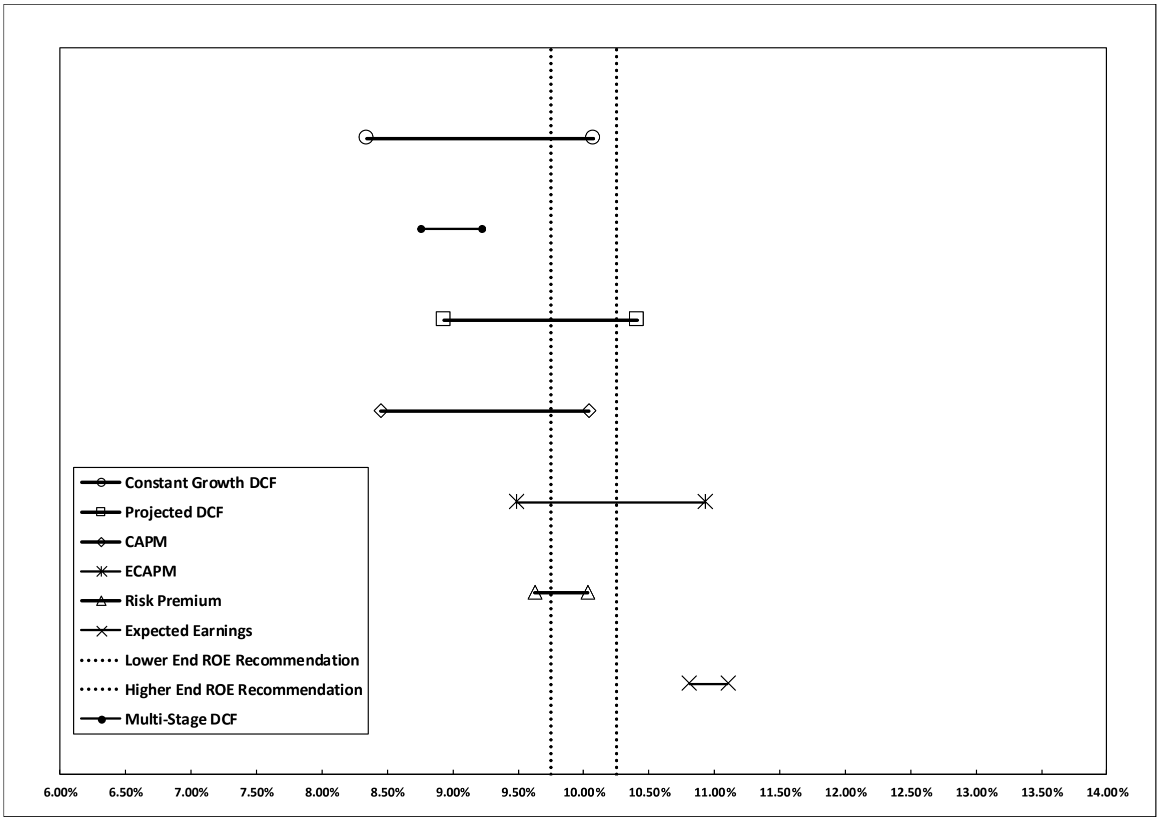
[3] *See Fed. Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va*, 262 U.S. 679 (1923).

estimation models produce a wide range of results. My conclusion about where within that range of results PacifiCorp's ROE falls is based on PacifiCorp's business and financial risk relative to the proxy group. Although the companies in my proxy group are generally comparable to PacifiCorp, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I selected a proxy group with similar, but not identical risk profiles, and I adjusted the results of my analysis either upward or downward within the reasonable range of results to account for any residual differences in risk.

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

A. I considered the results of three forms of the DCF model: the Constant Growth DCF, the Multi-Stage DCF, and a Projected DCF. In addition, I considered the results of the CAPM, ECAPM, Risk Premium, and Expected Earnings methodologies. The results of these analyses are summarized in Figure 1 below.

Figure 1: Summary of Cost of Equity Analytical Results[4]



As shown in Figure 1 (and in Exhibit PAC/404), the range of the Constant Growth DCF model results is wide, particularly in relation to the results of the other methodologies. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results is wide.

Furthermore, as shown in Exhibit PAC/404, the mean low Constant Growth DCF[5] results (prior to exclusions for outliers) for the proxy group, range from 7.53 percent to 7.72 percent for the 30-, 90-, and 180-day averaging periods. Thus,

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[4] The analytical results reflect the results of the Constant Growth DCF analysis excluding the results for individual companies that did not meet the minimum threshold of 7.00 percent.

[5] My DCF models generated a mean low, mean, and mean high result. The mean low result is the mean of the proxy group DCF results calculated using the lowest earnings growth rate for each company from Value Line, Yahoo! Finance or Zacks.

the mean low Constant Growth DCF results are below any authorized ROE for an electric or natural gas utility in the U.S. since at least 1980.[6] Therefore, I conclude that the mean low DCF results do not provide a sufficient risk premium to compensate equity investors for the residual risks of ownership, including the risk that they have the lowest claim on the assets and income of PacifiCorp.

Although I have concerns about the results produced by the DCF models, my ROE recommendation considers the range between the mean and mean-high results of the DCF models. In addition, I consider the results of forward-looking CAPM and ECAPM analyses, a Bond Yield Plus Risk Premium analysis, and an Expected Earnings analysis. I also consider company-specific risk factors, and current and prospective capital market conditions.

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

A. Based on the analysis presented in Section IX of my testimony, I conclude that PacifiCorp's proposed common equity ratio of 53.52 percent is reasonable. To make this determination, I reviewed the capital structures of the utility operating subsidiaries of the proxy companies. As shown in Exhibit PAC/413, the results of that analysis demonstrate that the equity ratios for the utility operating companies held by the proxy group range from 39.98 percent to 61.54 percent with an average of 52.87 percent. PacifiCorp's proposed common equity ratio of 53.52 percent closely approximates the average equity ratio for the utility operating subsidiaries of the proxy group companies and is well below the high-end of the range. Moreover,

[6] Source: Regulatory Research Associates, January 1, 1980 - November 29, 2019.

PacifiCorp's proposed common equity ratio is reasonable considering that federal tax reform legislation has had a negative effect on the cash flows and credit metrics of regulated utilities.

Furthermore, a fundamental aspect of the financial regulation of utilities is assuring that the subject utility has a reasonable opportunity to earn a return on capital consistent with the return available on investments of similar risk. While this principle is most often discussed in terms of the allowed ROE, it is equally applicable to all aspects of the overall Rate of Return (ROR). The equity return, which is the product of the ROE and the equity ratio, (*i.e.*, the Weighted Return on Equity (WROE)), ultimately defines the return to shareholders, and the product of the cost of debt and the debt ratio ensures that a company's debt obligations are met. Therefore, it is necessary to consider both the rates that are applied to debt and equity and the composition of the capital structure to determine the reasonableness of the ROR. Taken together, PacifiCorp's proposed common equity ratio of 53.52 percent and its requested ROE of 10.20 percent, result in a WROE of 5.46 percent. This return reasonably balances the interests of customers and shareholders by enabling PacifiCorp to maintain its financial integrity and therefore its ability to attract capital at reasonable terms and conditions under a variety of economic and financial market conditions.

IV. REGULATORY GUIDELINES

Q. Please describe the guiding principles used in establishing the cost of capital for a regulated utility.

A. The United States Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) that the end result, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[7]

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

A. Yes, it has. The Commission has acknowledged the legal precedent for a just and reasonable return established in the *Hope* and *Bluefield* decisions. In particular, in a 2007 decision for Portland General Electric Company, the Commission stated:

> Under these decisions, a utility's authorized rate of return, and the resulting overall rates, should be sufficient to maintain financial integrity, allow the utility to attract capital under reasonable terms, and be commensurate with returns investors could earn by investing in other enterprises of comparable risk. This standard has been codified in Oregon law. *See* ORS 756.040.[8]

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

Q. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A. An ROE that is adequate to attract capital at reasonable terms enables a utility to

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[7] *Hope,* 320 U.S. 591; *Bluefield*, 262 U.S. 679.

[8] *In the Matter of Portland General Elec. Co. Request for a General Rate Revision*, Docket Nos. UE 180, UE 181, and UE 184, Order No. 07-015 at 28 (Jan. 12, 2007).

continue to provide safe, reliable service while maintaining its financial integrity. To the extent the utility is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders are disadvantaged.

Q. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other natural gas and electric utilities. Therefore, the authorized ROE for a utility sends an important signal to investors regarding the level of regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have an incentive to direct their capital to those investments. Thus, an authorized ROE significantly below authorized ROEs for other natural gas and electric utilities can inhibit PacifiCorp's ability to attract capital for investment.

Q. What are your conclusions regarding regulatory guidelines?

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

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

V. CAPITAL MARKET CONDITIONS

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

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

As discussed in the remainder of this section, analysts and regulatory commissions have concluded that current market conditions affect the results of ROE estimation models. As a result, it is important to consider the effect of these conditions on ROE estimation models when determining the appropriate range and recommended ROE for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that ROE estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

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

A. The cost of equity for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: (1) valuations of utility stocks that are at historically high levels, which has an inverse relationship to dividend yields; (2) recent market uncertainty, its current effect on interest rates, and long-term expectations for interest rates; and (3) recent Federal tax reform. In this section, I discuss each of these factors and how it affects the models used to estimate the cost of equity for regulated utilities.

The Effect of Market Conditions on Valuations

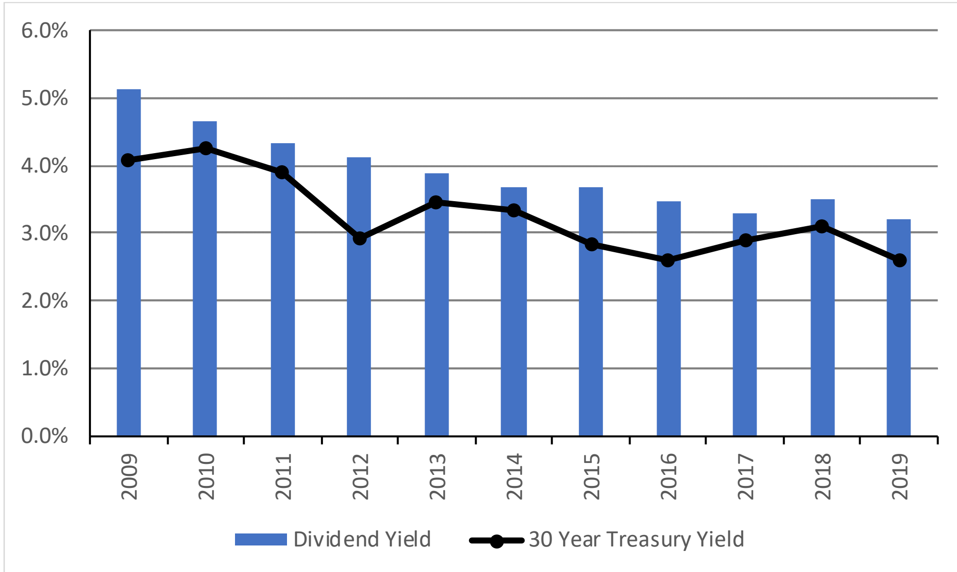
Q. How has the Federal Reserve's monetary policy affected capital markets in recent years?

A. Extraordinary and persistent federal intervention in capital markets artificially lowered government bond yields after the Great Recession of 2008–2009, as the Federal Open Market Committee (FOMC) used monetary policy (both reductions in short-term interest rates and purchases of Treasury bonds and mortgage-backed securities) to stimulate the U.S. economy. As a result of very low or zero returns on short-term government bonds, yield-seeking investors have moved into longer-term instruments, bidding up prices and reducing yields on those investments. As investors have moved along the risk spectrum in search of higher yields that meet their return requirements, there has been increased demand for dividend-paying equities, such as natural gas and electric utility stocks.

Q. How has the period of abnormally low interest rates affected the valuations and dividend yields of utility shares?

A. The Federal Reserve's accommodative monetary policy has caused investors to seek alternatives to the historically low interest rates available on Treasury bonds. As a result of this search for higher yield, share prices for many common stocks, especially dividend-paying stocks such as utilities, have been driven higher while the dividend yields (which are computed by dividing the dividend payment by the stock price) have decreased to levels well below the historical average. As shown in Figure 2, from 2009 through 2019, since the Federal Reserve intervened to stabilize financial markets and support the economic recovery after the Great Recession of 2008–2009, Treasury bond yields and utility dividend yields have declined. Specifically, Treasury bond yields declined by approximately 147 basis points, and electric utility dividend yields have decreased by about 194 basis points over this same period.

Figure 2: Dividend Yields for Electric Utility Stocks[9]



Q. How have higher stock valuations and lower dividend yields for utility companies affected the results of the DCF model?

A. During periods of general economic and capital market stability, the DCF model may adequately reflect market conditions and investor expectations. However, in the current market environment, the DCF model results are distorted by the historically low level of interest rates and the higher valuation of utility stocks. In October and December of 2019, Value Line addressed the high valuations of electric utilities:

> Most stocks covered in the Electric Utility Industry have fared very well in 2019. For the vast majority of these issues, the price has risen more than 10%. For some stocks, including Entergy, the quotation has soared 35%. The aforementioned reduction in interest rates (from a level that was already low) has induced income-oriented investors to reach for yield. This is despite the fact that the valuations of electric utility issues are historically high. The group's average dividend yield is just 3.2%, and the price-earnings ratios of most of these stocks is well above that

[9] Source: Bloomberg Professional. Figure 2 includes 2019 data through November 29, 2019.

> of the market. In fact, some recent quotations are above the 2022-2024 Target Price Range.[10]
>
> ***
>
> We advise investors to take a cautious stance due to the group's high valuation. The 18-month Target Price Ranges shown on the full-page reports for each stock do not reflect dividends, but even when dividends are added to these estimates, they do not suggest attractive total returns for this time frame. We do provide total return projections for the 3- to 5-year period. These are not appealing, either. In fact, the recent quotations for most of these stocks are within their 2022-2024 Target Price Range, and in some cases (such as IDACORP), the price is above this range.[11]

This is further supported by a recent Edward Jones report on the utility sector:

> Utility valuations have climbed back to record levels as 10-year Treasury bond rates have fallen back below 2%. On a price-to-earnings basis, [utility valuations] remain significantly above their historical average, and have been trading near all-time highs. We have seen utility valuations moving in line with interest rate movements, although there have been exceptions to this. Overall, however, we believe the low-interest-rate environment has been the biggest factor in pushing utilities higher since many investors buy them for their dividend yield.
>
> Utilities recently hit new all-time highs, and are still trading significantly above their average price-to-earnings ratio over the past decade. The premium valuation continues to reflect not only the low interest rate environment, but also the stable and predominantly regulated earnings growth we foresee.[12]

Furthermore, Bank of America Merrill Lynch recently commented on the risks of underperformance for certain utilities based on concerns about the valuation of the

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[10] ELECTRIC UTILITY (CENTRAL) INDUSTRY, *Value Line Investment Survey* at 901 (December 13, 2019).

[11] ELECTRIC UTILITY (WEST) INDUSTRY, *Value Line Investment Survey* at 2214 (October 25, 2019).

[12] Andy Smith. EDWARD JONES, *Utilities Sector Outlook* at 2 (October 18, 2019) (Reference to figure omitted).

sector, in particular the concern that the current premium on share prices may be largely unwarranted.[13]

As noted by equity analysts, over the last few years, utility stocks have experienced high valuations and low dividend yields driven by investors moving into dividend-paying stocks from bonds due to the low interest rates in the bond market. Conversely, if interest rates increase, bonds become a substitute for utility stocks, which results in an increase in dividend yields. As noted in the next section of my testimony, this change in market conditions that is expected over the long-term implies that the ROE calculated using historical market data in the DCF model may understate the forward-looking cost of equity.

Q. What is the effect of high valuations on utility stocks on the DCF model?

A. High valuations have the effect of depressing the dividend yields, which results in overall lower estimates of the cost of equity from the DCF model.

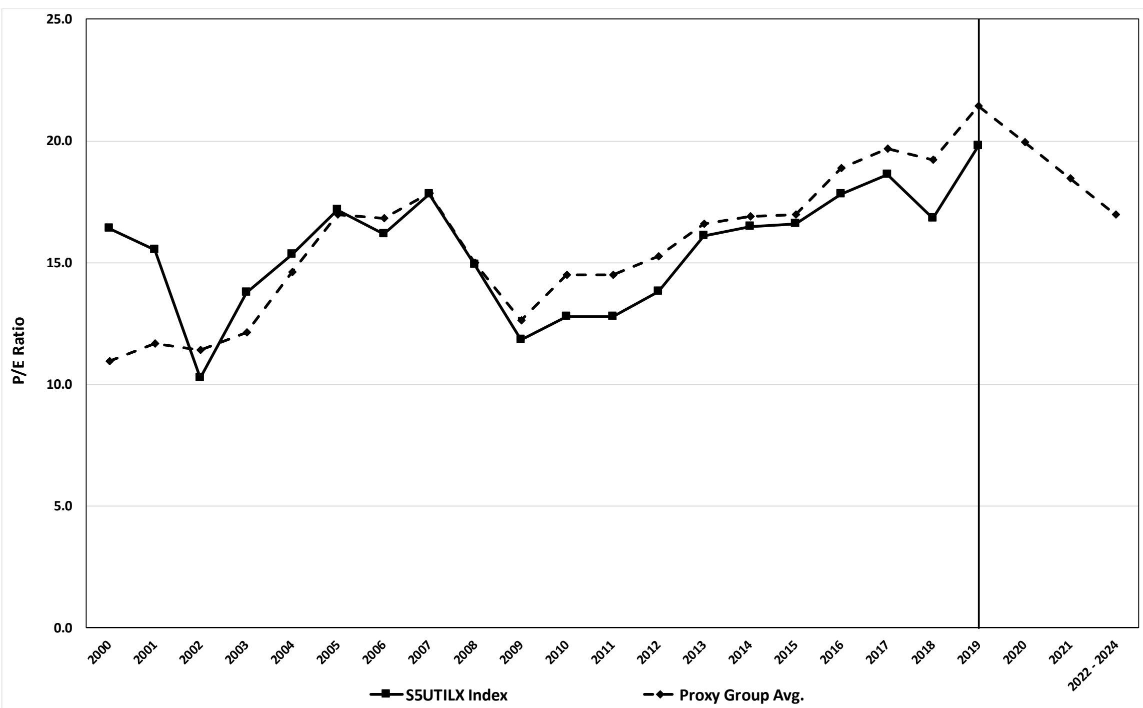
Q. How do current valuations of public utilities compare to the historical average?

A. Figure 3 summarizes the average historical and projected Price-to-Earnings (P/E) ratios for the proxy companies calculated using data from Bloomberg Professional and Value Line.[14] As shown in Figure 3, the average P/E ratio for the proxy companies increased from 2018 to 2019 as a result of uncertainty in markets surrounding the trade dispute between the U.S. and China. The uncertainty has resulted in investors shifting to defensive sectors such as utilities and consumer

[13] BofAML, *American Water Works AWKward valuation: Downgrading premium utility to underperform*, July 15, 2019. BofAML, *Eversource Energy, Reiterating our Underperform: Shares pricey relative to few updates*, July 15, 2019.
[14] Selection of the Proxy Companies is discussed in detail in Section VI of my direct testimony.

staples. This has driven the prices of utility stocks and thus the P/E ratios to unsustainable levels. In 2019, the average P/E ratio for the proxy companies has been 21.42, which is well above the average for the period of 2000–2018 of 15.39. It is not reasonable to expect the proxy companies to maintain P/E ratios that are well above long-term averages. As shown in Figure 3, Value Line is projecting that P/E ratios for the proxy companies will decline over the period of 2019 through 2022. All else equal, if P/E ratios for the proxy companies decline, as Value Line projects, the ROE results from the DCF model would be higher. Therefore, the DCF model using historical market data is likely understating the forward-looking cost of equity for the proxy group companies.

Figure 3: Average Historical Proxy Group P/E Ratios[15]



[15] Bloomberg Professional, historical data through November 29, 2019, and projected data from Value Line Investment Survey, July 26, 2019, August 16, 2019, and September 13, 2019.

Q. Have you reviewed any other market indicators that compare the current valuation of utilities to the historical average?

A. Yes. To further assess how the current low interest rate environment has affected the valuations of the companies in my proxy group, I reviewed the price/earnings to growth (PEG) ratio for the Standard & Poor's (S&P) Utilities Index. The PEG ratio is commonly used by investors to determine if a company is considered over- or under-valued. The ratio compares the P/E ratio of a company to the expected growth rate of future earnings. This allows investors to compare companies with similar P/E ratios but different earnings growth projections. If two companies have a P/E ratio of 20, but company A is growing at a rate of six percent and company B is growing at a rate of 15 percent, then on a relative valuation basis company B is the better investment.

As shown in a report published by Yardeni Research, Inc., the PEG ratio for the S&P Utilities Index is significantly higher than it has historically been because of the accommodative monetary policy pursued by the Federal Reserve following the Great Recession of 2008–2009.[16] While the PEG ratio has declined in recent years due to the Federal Reserve's shift to normalize monetary policy, the PEG ratio for the S&P Utilities Index is still above the historical average. In general, stocks with lower long-term PEG ratios are considered better values. As the PEG ratio increases above the long-term historical average, as has been the case with the S&P Utilities Index, then the stocks are considered relatively over-valued unless the growth rate increases to support the higher valuation. As of December 2019, the PEG ratio for the S&P

[16] YARDENI RESEARCH, INC., *S&P 500 Industry Briefing: Utilities* at 5 (December 16, 2019).

Utilities Index is close to 4.0, which indicates that many of the stocks in the index are currently trading at levels well above the historical average. This analysis supports Value Line's expectation that the P/E ratios of utilities will decline over the near to intermediate term.

Q. How do equity investors view the utilities sector based on these recent market conditions?

A. Investment advisors have suggested that utility stocks may underperform as a result of market conditions. Denise Chisholm, sector strategist at Fidelity Investments, recently commented that the high valuations of defensive sector stocks such as utilities are likely to result in sector rotation. Specifically, Ms. Chisholm explained that:

> Consumer staples, utilities, and health care are the most expensive they've been since 1970, in the top percentile. That data point has been not just informative, but also predictive in history. It's a rare signal that has only really occurred five times. You see a 1,000-basis-point rotation back to the economically sensitive sectors and an average underperformance of the defensive sectors.[17]

The Current and Expected Interest Rate Environment

Q. Please provide a brief summary of the recent monetary policy actions of the Federal Reserve.

A. At its December 2019 meeting, the Federal Reserve decided to maintain the current federal funds rate range of 1.50 percent to 1.75 percent and noted that the current range was appropriate for sustaining the current economic expansion and satisfying the Federal Reserve's goals of full employment and price stability.[18] Prior to the

[17] Leslie P. Norton, *It's time to stop playing defense in Stocks,* Barron's (Oct. 28, 2019) *available at* https://www.barrons.com/articles/its-time-to-stop-playing-defense-in-stocks-51571418847.
[18] Press Release, Federal Reserve, *FOMC* (Dec. 11, 2019).

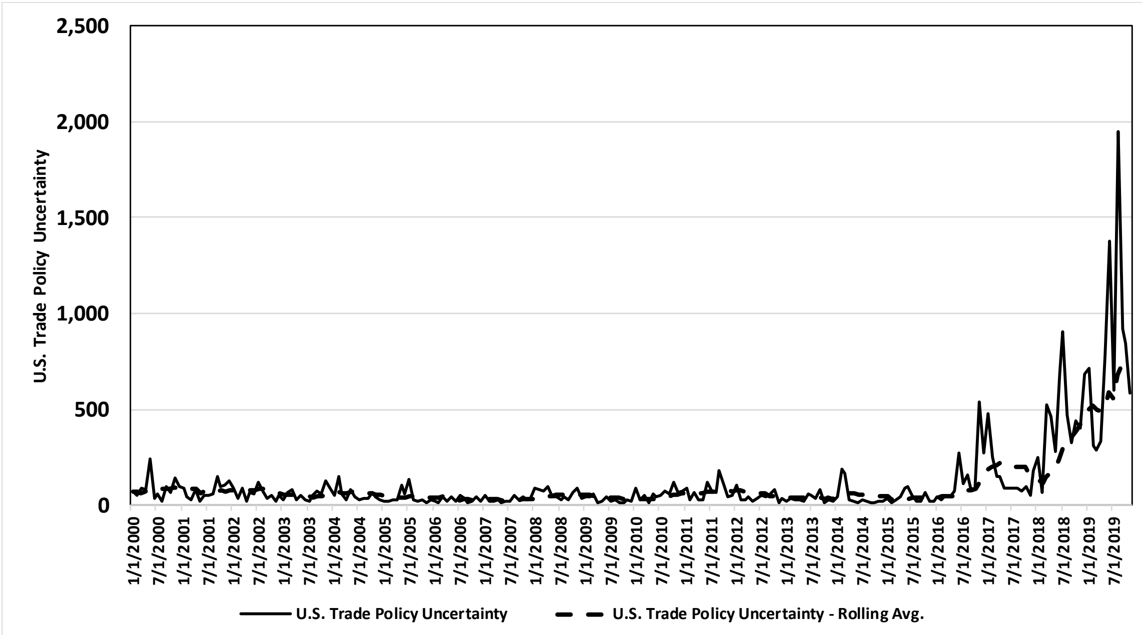
December 2019 meeting, the Federal Reserve reduced the federal funds rate three times in 2019 in response to economic effects of the trade dispute between the U.S. and China. The ongoing trade dispute has affected the global economy and caused a rise in volatility in financial markets; thus, the Federal Reserve reacted by reducing the federal funds rate to sustain the current economic expansion.

Q. Have you reviewed any market indicators that measure uncertainty in the market related to U.S. trade policy?

A. Yes. I reviewed the U.S. trade policy uncertainty index developed by economists Scott Baker, Nicholas Bloom, and Steven Davis. The index measures the frequency that articles in U.S. publications discuss economic policy uncertainty and reference trade policy.[19] As shown in Figure 4, uncertainty regarding U.S. trade policy is at its highest level since at least 2000, with the largest increase occurring in the last two years as a result of the escalating trade dispute between the U.S. and China.

[19] Source: Economic Policy Uncertainty: https://www.policyuncertainty.com/index.html.

Figure 4: U.S. Trade Policy Uncertainty Index



Q. How have the trade dispute with China and the recent uncertainty in the market affected the yields on long-term government bonds?

A. The uncertainty surrounding the trade dispute between the U.S. and China has resulted in a flight-to-quality as investors have purchased safer assets such as U.S. Treasuries due to increased fears of a possible recession. This has been increasingly evident over the past few months as investors responded to news of increases in tariffs by both China and the U.S.

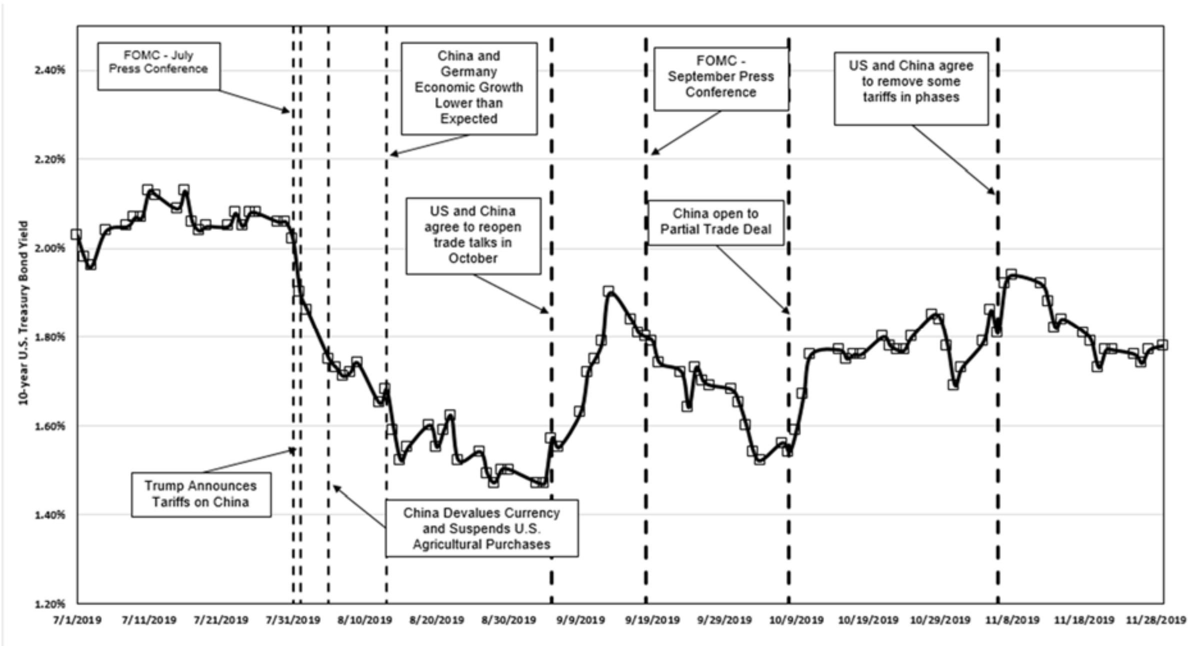
To illustrate the recent reactions of investors, I conducted an event study of the yield on the 10-year U.S. Treasury bond between July 1, 2019, and November 29, 2019. As shown in Figure 5, the yield on the 10-year U.S. Treasury Bond was relatively stable for the month of July; however, the yield decreased by approximately 50 basis points from the end of July to the middle of August. The recent decline was due to investors responding to events associated with the trade dispute. For example, the market reacted negatively to Chairman Powell's comments following the FOMC meeting at the end of July and President Trump's announcement that the U.S. was going to impose tariffs on the remaining set of goods imported from China. These two events accounted for a decrease of approximately 25 basis points in the yield on the 10-year Treasury between July 30, 2019, and August 5, 2019.

Conversely, positive developments in the trade dispute between the U.S. and China have led to increases in the yield on the 10-year Treasury bond. For example, the yield on the 10-year Treasury bond increased following news on September 5, 2019, that the U.S. and China would reopen trade discussions in October 2019. Moreover, recent news of a partial trade deal and the removal of some of the tariffs in phases has the 10-year Treasury bond yield at 1.78 percent as of November 29, 2019, which is a 31-basis point increase over the recent low in August 2019 of 1.47 percent. On January 15, 2020, the U.S. and China signed a Phase I trade deal. This deal does not resolve all of the trade dispute, however, and negotiations continue between the two countries on other aspects of the trade agreement.

The recent volatility in the market as a result of the trade dispute led Bloomberg to note in an article that volatility in the market on any given day is being determined more and more by the words and actions of Chairman Powell, President Trump, and the President of China, Xi Jinping.[20]

[20] Michael P. Regan, *Powell Speaks, Trump Tweets, China Reacts, Markets Freak. Repeat*, BLOOMBERG, (8 Aug. 2019) *available at* www.bloomberg.com/news/articles/2019-08-08/powell-speaks-trump-tweets-china-reacts-markets-freak-repeat.

Figure 5: 10-year U.S. Treasury Bond Yield



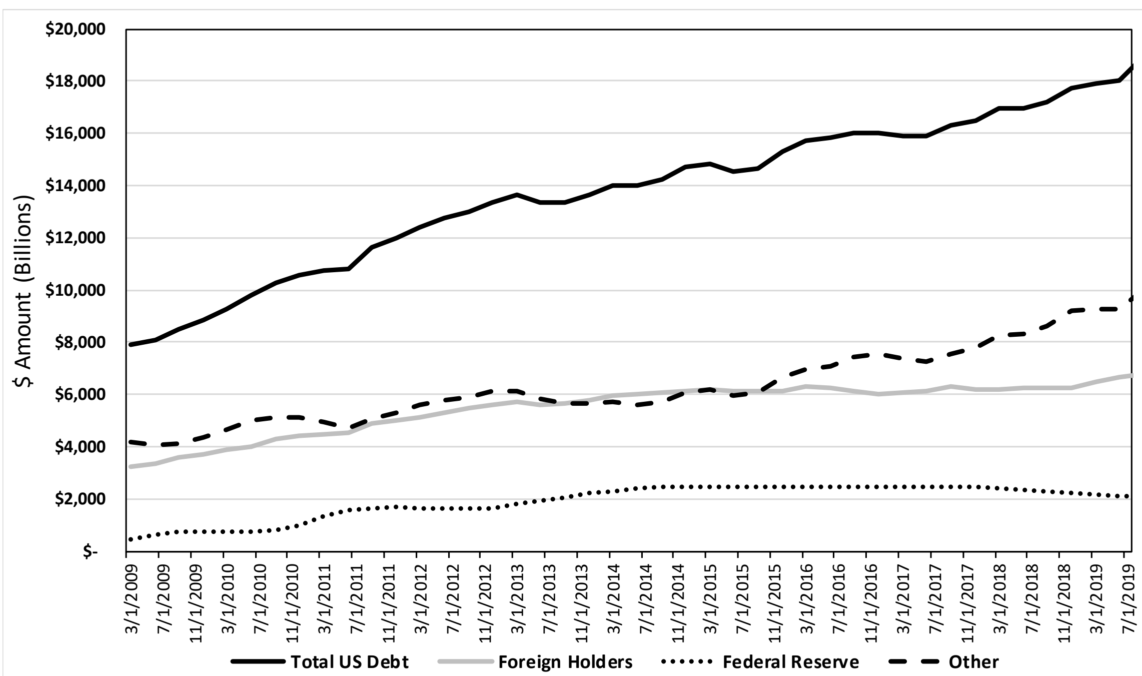
Q. Is the recent decline in long-term government bond yields as a result of U.S. trade policy uncertainty indicative of the longer-term outlook for yields on these instruments?

A. No. While the yields on long-term government bonds have decreased recently, this is not indicative of a long-term trend. It is more indicative of a shift in the type of investors purchasing the long-term government bonds. As shown in Figure 6, the total amount of debt owned by the Federal Reserve and Foreign Holders has been relatively stable or slightly declining over the past few years, while the demand from private sector investors has been increasing. This is important because private sector investors are more price-sensitive and more likely to respond quickly to changes that occur in the market. This explains the decline in long-term government bond yields that occurred in recent months as investors reacted to the uncertain economic conditions due to the trade dispute between the U.S. and China. As a result, long-term bond yields could increase quickly if a trade agreement is reached between the U.S. and China. For example, Kiplinger recently noted:

> While the trade war lasts, 10-year Treasury note rates are likely to remain 2% or a bit lower. Mortgage rates will stay around the current 3.6% for 30-year fixed, 3.1% for 15-year. If the trade war relents, we expect that 10-year Treasury notes could rise to the mid-to-upper 2% range. The 30-year fixed-rate mortgage would also rise to 4.2%, and the 15-year fixed-rate mortgage to 3.7%.[21]

In fact, as shown in Figure 5, long-term bond yields have increased between August 2019 and November 2019 in response to positive developments in the trade dispute between the U.S. and China.

Figure 6: Ownership of U.S. Debt – 2009 – 2019[22]



[21] David Payne. *Expect Two More Interest-Rate Cuts by the Fed.*, Kiplinger's Personal Finance (12 August 2019).

[22] Bloomberg Professional, Data through November 29, 2019.

Q. What is the financial market's perspective on the future path of long-term government bond yields?

A. According to the December 2019 issue of Blue Chip Financial Forecasts, the yields on 10- and 30-year Treasury bonds are expected to increase over the near-term of Q1 2020 to Q1 2021.[23] Similarly, strategists at both JP Morgan Chase and Merrill Lynch are projecting increases in long-term government bond yields over the near-term. Merrill Lynch is projecting that the yield on the 10-year Treasury Bond will increase to 2.00 percent by the end of 2019,[24] while strategists at JP Morgan Chase indicated that yields on the 10-year Treasury Bond could increase up to 100 basis points over the next six months.[25]

Q. What are your conclusions regarding the current interest rate environment and its effect on the cost of equity for PacifiCorp?

A. Investors have responded to the recent escalation in the trade war between the U.S. and China by divesting higher-risk assets and purchasing lower-risk assets such as U.S. Treasury bonds. However, the trade dispute between the U.S. and China is not expected to continue over the long-term. This view is consistent with that of Chairman Powell who, as noted above, sees an improvement in the risk associated with trade policy. As interest rates increase, the cost of equity for the proxy companies using the DCF model is likely to be an overly-conservative estimate of investors' required returns because the proxy group average dividend yield reflects

[23] Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 2.
[24] MERRILL, CHIEF INVESTMENT OFFICE, *Capital Market Outlook* at 8 (November 18, 2019).
[25] Joanna Ossinger, *JPMorgan Says Treasury Yields to Surge in 1995 Cycle Replay.* BLOOMBERG (Nov. 3 2019) *available at* www.bloomberg.com/news/articles/2019-11-04/jpmorgan-says-treasury-yields-to-surge-in-replay-of-1995-cycle.

the increase in stock prices that resulted from substantially lower interest rates. As such, the real prospect of rising interest rates supports the selection of a return well above the mean ROE estimate from the DCF analysis. Alternatively, my CAPM and Bond Yield Plus Risk Premium analyses also include estimated returns based on projected interest rates, reflecting investors' expectations of market conditions over the period that the rates established in this proceeding will be in effect.

Effect of Tax Reform on the ROE and Capital Structure

Q. Are there other factors that should be considered in determining the cost of equity for PacifiCorp?

A. Yes. The effect of the Tax Cuts and Jobs Act (TCJA) should also be considered in the determination of the cost of equity. It is also relevant to setting the equity ratio in the capital structure, which I address in Section IX of my direct testimony. The credit rating agencies have commented on the effect of the TCJA on regulated utilities. In summary, the TCJA is expected to reduce utility revenues due to the lower federal income taxes, the end of bonus depreciation, and the requirement to return excess Accumulated Deferred Income Taxes (ADIT). This change in revenue is expected to reduce Funds From Operations (FFO) metrics across the sector, and absent regulatory mitigation strategies, is expected to lead to weaker credit metrics and negative ratings actions for some utilities.[26]

Q. Have credit or equity analysts commented on the effect of the TCJA on utilities?

A. Yes. Each of the credit rating agencies has indicated that the TCJA would have an

[26] FITCHRATINGS, *Special Report, What Investors Want to Know, Tax Reform Impact on the U.S. Utilities, Power & Gas Sector* (Jan. 24, 2018).

overall negative credit impact on regulated operating companies of utilities and their holding companies due to the reduction in cash flow that results from the change in the federal tax rate and the loss of bonus depreciation.

Moody's noted that the rates that regulators allow utilities to charge customers is based on a cost-plus model, with tax expense being one of the pass-through items. Utilities will collect less income tax at a lower rate, reducing revenue. In addition, with the loss of bonus depreciation, the timing of future cash tax payments will be accelerated. Therefore, utilities will collect less tax revenue as a result of the lower tax rate and retain less of the collected taxes as a result of the loss of bonus depreciation. All else being equal, the changes will have a negative effect on utility cash flows and will, ultimately, negatively impact the utilities' ability to fund ongoing operations and capital improvement programs.

In S&P's 2019 trends report, the rating agency notes that the utility industry's financial measures weakened in 2018 and attributed that to tax reform, capital spending, and negative load growth. In addition, S&P expects that weaker credit metrics will continue into 2019 for those utilities operating with minimal financial cushion. S&P further expects that these utilities will look to offset the revenue reductions from tax reform with equity issuances. That rating agency reported that in 2018 regulated utilities issued nearly $35 billion in equity, which is more than twice the equity issuances in either 2016 or 2017.[27]

FitchRatings (Fitch) also indicated that any ratings actions will be guided by the response of regulators and the management of the utilities. Fitch notes that the

[27] Standard & Poor's Ratings, *Industry Top Trends 2019, North America Regulated Utilities*, November 8, 2018.

solution will depend on the ability of utility management to manage the cash flow implications of the TCJA. Fitch offered several solutions to provide rate stability and to moderate changes to cash flow in the near term, including increasing the authorized ROE and/or equity ratio.[28]

Q. Has Moody's responded to the increased risk for utilities resulting from the TCJA?

A. Yes. In 2018, Moody's issued a report changing the rating outlook for several regulated utilities from Stable to Negative.[29] Moody's noted that the rating change affected companies with limited cushion in their ratings for deterioration in financial performance. Later that year, Moody's downgraded the outlook for the entire regulated utility industry from Stable to Negative for the first time ever, citing ongoing concerns about the negative effect of the TCJA on cash flows of regulated utilities. Since mid-2018, Moody's has downgraded the credit ratings of several utilities based in part on the effects of tax reform on financial metrics. As shown in Figure 7, the downgrades have continued throughout 2019.

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[28] FITCHRATINGS, *Special Report, What Investors Want to Know, Tax Reform Impact on the U.S. Utilities, Power & Gas Sector* (Jan. 24, 2018).
[29] MOODY'S INVESTOR SERVICE, Global Credit Research, *Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform* (Jan. 19, 2018).

1 **Figure 7: Credit Rating Downgrades Resulting from TCJA**

Utility	Rating Agency	Credit Rating before TCJA	Credit Rating after TCJA	Downgrade Date
Wisconsin Power and Light Company	Moody's	A2	A3	12/11/2019
Vectren Utility Holdings	Moody's	A2	A3	10/25/2019
Southern Indiana Gas & Electric Company	Moody's	A2	A3	10/25/2019
Indiana Gas Company	Moody's	A2	A3	10/25/2019
El Paso Electric Company	Moody's	Baa1	Baa2	9/17/2019
Questar Gas Company	Moody's	A2	A3	8/15/2019
DTE Gas Company	Moody's	A2	A3	7/22/2019
South Jersey Gas Company	Moody's	A2	A3	7/17/2019
Central Hudson Gas & Electric	Moody's	A2	A3	7/12/2019
Oklahoma Gas & Electric Company	Moody's	A2	A3	5/31/2019
American Water Works	Moody's	A3	Baa1	4/1/2019
Niagara Mohawk Power Corporation	Moody's	A2	A3	3/29/2019
KeySpan Gas East Corporation (KEDLI)	Moody's	A2	A3	3/29/2019
Xcel Energy	Moody's	A3	Baa1	3/28/2019
ALLETE, Inc.	Moody's	A3	Baa1	3/26/2019
Brooklyn Union Gas Company (KEDNY)	Moody's	A2	A3	2/22/2019
Avista Corp.	Moody's	Baa1	Baa2	12/30/2018
Consolidated Edison Company of New York	Moody's	A2	A3	10/30/2018
Consolidated Edison, Inc.	Moody's	A3	Baa1	10/30/2018
Orange and Rockland Utilities	Moody's	A3	Baa1	10/30/2018
Southwestern Public Service Company	Moody's	Baa1	Baa2	10/19/2018
Dominion Energy Gas Holdings	Moody's	A2	A3	9/20/2018
Piedmont Natural Gas Company, Inc.	Moody's	A2	A3	8/1/2018
WEC Energy Group, Inc.	Moody's	A3	Baa1	7/12/2018
Integrys Holdings Inc.	Moody's	A3	Baa1	7/12/2018
OGE Energy Corp.	Moody's	A3	Baa1	7/5/2018
Oklahoma Gas & Electric Company	Moody's	A1	A2	7/5/2018

Q. Is it reasonable to expect that investors have included the negative effects of the TCJA on the cash flows of utilities in their valuation models?

A. Not entirely. It is reasonable to expect that investors have reviewed the reports published by the credit rating agencies such as Moody's, S&P, and Fitch and are therefore considering the effects of the TCJA. However, utilities are still managing the negative effects of the TCJA and are working with regulators to determine appropriate solutions to mitigate the effect of the TCJA on cash flows. As Moody's noted in its November 2018 report, the TCJA is expected to continue to have a near-term effect on the cash flows of utilities, which resulted in Moody's negative outlook on the industry for 2019.[30] Furthermore, as shown in Figure 7, Moody's is continuing to evaluate the effect of the TCJA on the cash flows of individual utilities. As part of the credit evaluation, rating agencies are specifically considering the recent rate case decisions of utilities to determine if the results of these cases help to mitigate the effect of the TCJA on cash flows. Therefore, the credit rating agencies appear to be continuing to monitor the effects of the TCJA on utilities.

Q. Has the Commission recognized that the TCJA has had an adverse impact on utility cash flows and credit ratings?

A. Yes. In February 2019, the Commission adopted Staff's memorandum recommending approval of an application by Avista Corp. (Avista) to issue stock.[31]

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[30] MOODY'S INVESTORS SERVICE, *Regulated utilities – US: 2019 outlook shifts to negative due to weaker cash flows, continued high leverage* at 3 (June 18, 2018).

[31] *In the matter of Avista Corp., dba Avista Utilities, Application for Authorization to Issue 3,500,000 Shares of Common Stock*, Docket No. UF 4308, Order No. 19-067 (Feb. 23, 2019).

Staff's memorandum included the following statements about the TCJA and the importance of maintaining strong credit ratings:

> Staff finds that the Tax Cuts and Jobs Act of 2017 created unanticipated stresses on the Company's credit ratings. The requested authorization signals to rating agencies that the Company is committed to the equity portion of its capital structure. However, it is Staff's finding that restoring a notch in credit ratings involves more than just remedying the cause for the downgrade. On December 21, 2018, Moody's stated, "Avista's credit profile reflects its low-risk vertically integrated electric and gas utility business, regulatory uncertainty in WA and the expected negative cash flow impact of tax reform." Authorization herein as recommended by Staff starts the process of addressing rating agency concerns and restoring a positive credit outlook.

In July 2019, the Commission approved Avista's application to issue debt securities, adopting the Staff's memorandum stating that "raising the Company's credit ratings back up a notch will require hard work and persistence on the part of Avista's finance group as well as a supportive regulatory environment and achieving target metrics."[32]

In January 2019, the Commission adopted Staff's memorandum recommending approval of Portland General Electric Company's (PGE) application to refresh a revolving credit facility. Staff's memorandum contained similar observations about the TCJA and credit ratings:

> Of concern to Staff is Moody's approach to the impacts of the [TCJA]. While one might expect lower taxes would be inherently positive news for utilities, Moody's has focused in on cash flow metrics that are stressed by the recent tax reform. Timely refreshment of this credit facility while PGE is under no heavy time or market pressure is consistent with provision for ongoing liquidity in support of current credit ratings. While approval of this Application does not by itself answer all of Moody's

[32] *In the matter of Avista Corporation, dba Avista Utilities, Application for Authorization to Issue and Sell $600,000,000 of Debt Securities,* Docket UF 4313, Order No. 19-249 (July 30, 2019).

> concerns regarding tax reform impacts on the utility sector, the proposed replacement credit facility is consistent with prudent financial management by the Company and will likely be seen as credit positive by both Standard and Poor's and Moody's. As the spreads over benchmark interest rates applicable to PGE depend on the level of the Company's credit ratings, this will be an area for the Commission to continue to monitor.[33]

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

A. Yes. In a recent rate case for Consumers Energy Company in Michigan, Case No. U-18322, the Michigan Public Service Commission (Michigan PSC) Staff recommended a 9.80 percent ROE based on the results of the DCF, CAPM, and Risk Premium approaches, which was supported by the Administrative Law Judge (ALJ).[34] In its Order issued on March 29, 2018, however, the Michigan PSC partly disagreed with the ALJ and Staff regarding expected market conditions and authorized a 10.00 percent ROE for Consumers Energy Company. The Michigan PSC noted that:

> [i]n setting the ROE at 10.00%, the Commission believes there is an opportunity for the company to earn a fair return during this period of atypical market conditions. This decision also reinforces the Commission's belief that customers do not benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner. The fact that other utilities have been able to access capital despite lower ROEs, as argued by many intervenors, is also a relevant consideration. It is also important to consider how extreme market reactions to singular events, as have occurred in the recent past, may impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. The Commission will continue to monitor a variety of market factors in future rate

[33] *In the matter of Portland Gen. Elect. Co., Request for Authority to Extend the Maturity of an Existing $500 Million Revolving Credit Agreement,* Docket UF 4272(3), Order No. 19-025 at Appendix A, p. 9 (Jan. 23, 2019) (emphasis added).

[34] *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-18322, Order at 37 (March 29, 2018).

> cases to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE.[35]

The Michigan PSC references "singular events" and the overall effect the events could have on the ability of a utility to access capital. Consistent with the Michigan PSC's views, it is important to consider that the TCJA has had a negative effect on the cash flows of utilities. In addition, it is important to consider this reduced cash flow in the context of overall market conditions when determining the appropriate ROE and equity ratio to enable PacifiCorp the ability to attract capital. As a result, it is imperative that the Commission authorize an ROE that will allow PacifiCorp to attract capital at reasonable terms during the period that rates will be in effect.

Q. What conclusions do you draw from your analysis of capital market conditions?

A. The important conclusions resulting from capital market conditions are:

- The assumptions used in the ROE estimation models have been affected by recent historical market conditions.
- Recent market conditions are not expected to persist as yields on long-term bonds are expected to increase. As a result, the recent historical market conditions are not reflective of the market conditions that will be present when the rates for PacifiCorp will be in effect.
- It is important to consider the results of a variety of ROE estimation models, using forward-looking assumptions to estimate the cost of equity.
- Without adequate regulatory support, the TCJA will have a negative effect on utility cash flows, which increases investor risk expectations for utilities.

[35] *Id.* at 43.

VI. PROXY GROUP SELECTION

Q. Why have you used a group of proxy companies to estimate the cost of equity for PacifiCorp?

A. In this proceeding, I am estimating the cost of equity for an electric utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and given that PacifiCorp's electric operations in Oregon do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to PacifiCorp in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process.

Even if PacifiCorp were a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to PacifiCorp, and thus provide a reasonable basis to derive an estimate of the appropriate ROE for PacifiCorp.

Q. Please provide a brief profile of PacifiCorp.

A. PacifiCorp is an indirect, wholly owned subsidiary of BHE. PacifiCorp provides electric utility service to approximately 1.9 million residential, commercial and industrial customers in California, Idaho, Oregon, Utah, Washington, and Wyoming.[36] In Oregon, PacifiCorp provides electric service to approximately 615,000 residential,

[36] Berkshire Hathaway Energy Co., 2018 Form 10-K, at 2.

commercial, and industrial customers.[37] As of December 31, 2018, PacifiCorp owned net utility electric plant in Oregon of approximately $4.5 billion.[38] PacifiCorp's electric operations in Oregon represented 23 percent of PacifiCorp's electric sales in 2018.[39] PacifiCorp currently has an investment grade long-term rating of A (Outlook: Stable) from S&P and A3 (Outlook: Stable) from Moody's.[40]

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

A. I began with the group of 37 companies that Value Line classifies as Electric Utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends, because companies that do not cannot be analyzed using the Constant Growth DCF model;
- have investment grade long-term issuer ratings from S&P and/or Moody's;
- are covered by at least two utility industry analysts;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- own regulated generation assets that are in rate base;
- have more than five percent of owned regulated generation capacity come from regulated coal-fired power plants;
- derive more than 60.00 percent of their total operating income from regulated operations;
- derive more than 60.00 percent of regulated operating income from regulated electric operations; and
- were not parties to a merger or transformative transaction during the analytical periods relied on.

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[37] *See* Exhibit PAC/100, Bird/3-4.
[38] *Pacific Power Results of Operations,* Docket No. RE 56, PacifiCorp's Annual Results of Operations Report ending December 31, 2018 (Apr. 30, 2019) (refer to page 1.0, lines 33, 47, and 48).
[39] Berkshire Hathaway Energy Co., 2018 Form 10-K, at 3.
[40] SNL Financial, January 8, 2020.

Q. What is the composition of your proxy group?

A. The screening criteria discussed above are shown in Exhibit PAC/403 and results in a proxy group consisting of the 23 companies shown in Figure 8 below.

Figure 8: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CenterPoint Energy, Inc.	CNP
CMS Energy Corporation	CMS
Dominion Resources, Inc.	D
DTE Energy Company	DTE
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
FirstEnergy Corporation	FE
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
PNM Resources, Inc.	PNM
Portland General Electric Company	POR
PPL Corporation	PPL
Southern Company	SO
Xcel Energy Inc.	XEL

VII. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return.

A. The overall ROR for a regulated utility is based on its weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q. How is the required ROE determined?

A. The required ROE is estimated by using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

Q. What methods did you use to determine PacifiCorp's ROE?

A. I considered the results of the Constant Growth DCF model, a Multi-Stage DCF model, a Projected Constant Growth DCF model, the CAPM and ECAPM, the Bond Yield Plus Risk Premium approach, and an Expected Earnings analysis. As discussed in more detail below, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

Importance of Multiple Analytical Approaches

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

A. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[41] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[42] recommend the CAPM, DCF, and Bond Yield Plus Risk Premium approaches.

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

A. Yes. Low interest rates and the effects of the investor "flight to quality" can be seen in high utility share valuations, relative to historical levels and relative to the broader market. Higher utility stock valuations produce lower dividend yields and result in lower cost of equity estimates from a DCF analysis. Low interest rates also affect the CAPM in two ways: (1) the risk-free rate is lower; and (2) because the market risk

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[41] TOM COPELAND, TIM KOLLER AND JACK MURRIN, VALUATION: MEASURING AND MANAGING THE VALUE OF COMPANIES, at 214 (3rd ed. 2000).
[42] EUGENE BRIGHAM, LOUIS GAPENSKI, FINANCIAL MANAGEMENT: THEORY AND PRACTICE at 341 (7th ed. 1994).

premium is a function of interest rates, (i.e., it is the return on the broad stock market less the risk-free interest rate), the risk premium should move higher when interest rates are lower. Therefore, it is important to use multiple analytical approaches to moderate the impact that the current low interest rate environment is having on the ROE estimates for the proxy group and, where possible, consider using projected market data in the models to estimate the return for the forward-looking period.

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

A. Yes. In previous cases, the Commission has considered the results of many ROE estimation models and determined, based on the results of those models, whether or not to place any weight on the model in its final determination. Specifically, in prior PacifiCorp and PGE cases, the Commission considered the results of DCF and CAPM models and concluded that the results of the CAPM were too low to be reasonable. Importantly, in those cases, the Commission did not reject the methodology entirely, but rather concluded that based on the specification of the model, the results were unreasonable and therefore should be given no weight. In the order in PacifiCorp's case, the Commission stated:

> While the results in this case cast further doubt on the validity of Staff's CAPM methodology, we do not believe that CAPM should be rejected in its entirety. We continue to believe that, in certain cases, CAPM analyses may provide a useful and reliable addition to the DCF results for determining cost of equity. After our review of the results in this case, however, we further conclude that the CAPM does not provide supportable and reasonable results in this docket. Accordingly, we give no weight to the CAPM results in determining an appropriate cost of equity for PacifiCorp.[43]

[43] *In the Matter of PacifiCorp's Proposal to Restructure and Reprice Its Services In Accordance with Senate Bill 1149*, Docket No. UE 116, Order No. 01-787 (Sept. 7, 2001).

The Commission reached the same conclusion in the concurrent PGE case.[44]

Q. Are you aware of any other regulatory commissions that have recognized that recent conditions in capital markets are causing ROE recommendations based on DCF models to be unreasonable?

A. Yes, several regulatory commissions have addressed the effect of capital market conditions on the DCF model, including the Illinois Commerce Commission (ICC), the Pennsylvania Public Utility Commission (PPUC), the Missouri Public Service Commission (Missouri PSC), and the New Jersey Board of Public Utilities (NJ Board).

Q. How have the PPUC, the ICC, the Missouri PSC, and the NJ Board addressed the effect of market conditions on the DCF?

A. In a 2012 decision for PPL Electric Utilities, the PPUC noted that it had traditionally relied primarily on the DCF method to estimate the cost of equity for regulated utilities, but the PPUC recognized that market conditions were causing the DCF model to produce results that were much lower than other models such as the CAPM and Bond Yield Plus Risk Premium. The PPUC's Order supported the consideration of multiple ROE estimation methodologies.[45]

The PPUC ultimately concluded:

> As such, where evidence based on the CAPM and RP methods suggest that the DCF-only results may understate the utility's current cost of equity capital, we will give consideration to those

[44] *In the Matter of Portland Gen. Elec. Proposal to Restructure and Reprice Its Services In Accordance with Senate Bill 1149*, Docket No. UE 115, Order No. 01-777 (Aug. 31, 2001).
[45] Pennsylvania Pub. Util. Comm'n, PPL Elec. Utilities, R-2012-2290597, meeting held December 5, 2012, at 80.

> other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination.[46]

In a 2016 ICC case involving Illinois-American Water Company, Staff relied on a DCF analysis that resulted in average returns for their proxy groups of 7.24 percent to 7.51 percent. The company demonstrated that these results were uncharacteristically low by comparing the results of Staff's models to recently authorized ROEs for regulated utilities and the return on the S&P 500.[47] The ICC agreed with the company that Staff's proposed ROE of 8.04 percent was anomalous and recognized that a return that is not competitive will deter investment in Illinois.[48] In setting the return in that proceeding, the ICC recognized that it was necessary to consider other factors beyond the outputs of the financial models, particularly whether the return is sufficient to attract capital, to maintain financial integrity, and to produce returns commensurate with returns for companies of comparable risk, while balancing the interests of customers and shareholders.[49]

In February 2018, the Missouri PSC issued a decision in Spire's 2017 natural gas rate case, in which the allowed ROE was set at 9.80 percent. In explaining the rationale for its decision, the Missouri PSC cited the importance of considering multiple methodologies to estimate the cost of equity and the need for the authorized

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[46] *Id.*, at 81.

[47] State of Illinois Commerce Comm'n, Docket No. 16-0093, Illinois-American Water Co. Initial Brief, August 31, 2016, at 10 (Illinois-American Initial Brief).

[48] Illinois Staff's analysis and recommendation in that proceeding were based on its application of the multi-stage DCF model and the CAPM to a proxy group of water utilities.

[49] Illinois-American Initial Brief, at 55.

ROE to be consistent with returns in other jurisdictions and to reflect the growing economy and investor expectations for higher interest rates.[50]

Finally, in its order in docket ER12111052 for Jersey Central Power and Light Company, the NJ Board noted that rate of return experts use a number of models including the DCF, CAPM, Risk Premium, and Comparable Earnings to estimate the return required by investors.[51] Moreover, the NJ Board stated that each of these models provide estimates of the return required by investors; however, the estimates are not necessarily precise and have been affected by the current economic environment, which is still recovering from the Great Recession of 2008-2009.[52] In the order, the NJ Board accepted the ROE recommendation by Staff, which was supported by the ALJ and based on a review of each of the model results presented by the witnesses in the case and recently authorized ROEs in other jurisdictions.[53] In supporting the recommendation of Staff, the ALJ concluded that the results of each model are affected by multiple factors, including current market conditions.

Q. What are your conclusions about the results of the DCF and CAPM models?

A. Recent market data that is used as the basis for the assumptions for both models have been affected by market conditions. As a result, relying exclusively on historical assumptions in these models, without considering whether these assumptions are consistent with investors' future expectations, will underestimate the cost of equity

[50] File No. GR-2017-0215 and File No. GR-2017-0216, Missouri Pub. Serv. Comm'n, Report and Order, Issue Date February 21, 2018, at 34.
[51] NJ Board Docket No. ER12111052, NJ Office of Administrative Law Docket No. PUC16310-12, Order Adopting Initial Decision with Modifications and Clarifications, March 18, 2015, at 71.
[52] *Id.*
[53] *Id.* at 10.

that investors would require over the period that the rates in this case are to be in effect. In this instance, relying on the historically low dividend yields that are not expected to continue over the period that the new rates will be in effect would underestimate the ROE for PacifiCorp.

The use of recent historical Treasury bond yields in the CAPM also tends to underestimate the projected cost of equity. Recent experience indicates that interest rates will increase over the near-term. The expectation that bond yields will not remain at currently low levels means that the expected cost of equity would be higher than is suggested by the CAPM using historical average yields. The use of projected yields on Treasury bonds results in CAPM estimates that are more reflective of the market conditions that investors expect during the period that PacifiCorp's rates will be in effect.

Constant Growth DCF Model

Q. Please describe the DCF approach.

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

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \quad [1]$$

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

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

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

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

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

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

A. The dividend yield in my Constant Growth DCF model is based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended November 29, 2019.

Q. Why did you use 30-, 90-, and 180-day averaging periods?

A. In my Constant Growth DCF model, I use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the ROE is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long-term. However, the averaging periods that I use rely on historical prices which, as discussed above, are currently at unsustainably high levels that are not expected to continue during the period that PacifiCorp's rates will be in effect. The use of current prices in the Constant Growth DCF model is not consistent with forward-looking market expectations. Therefore, the results of my Constant Growth DCF model using historical data may underestimate the forward-looking cost of equity. As a result, I place more weight on the mean to mean-high results produced by my Constant Growth DCF model.

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

A. Yes, I did. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first year dividend yield is, on average, representative of the coming 12-month period, and does not overstate the aggregated dividends to be paid during that time.

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

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

Q. Which sources of long-term earnings growth rates did you use?

A. My Constant Growth DCF model incorporates three sources of long-term earnings growth rates: (1) Zacks Investment Research; (2) Thomson First Call (provided by Yahoo! Finance); and (3) Value Line Investment Survey.

Multi-Stage DCF Model

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

A. Consistent with Commission precedent, I also considered the results of a Multi-Stage form of the DCF model. As with the Constant Growth DCF model, the Multi-Stage form defines the cost of equity as the discount rate that sets the current price equal to the discounted value of future cash flows. While the Multi-Stage DCF model is a method the Commission has relied upon in the past, as noted above, the Commission has also recognized that it is important to consider whether a model used to estimate the ROE is producing just and reasonable results at a given point in time.[54] This can be accomplished by comparing the individual and collective results of the various models used to estimate the cost of equity, and by evaluating whether the inputs and assumptions of the models are affected by conditions in capital markets or the economy. In the current market environment, high valuations and low dividend yields for utility stocks are causing both the Constant Growth and Multi-Stage DCF model to produce unreliable results. Earnings growth rates for utility companies, a

[54] Order No. 01-787.

focus of the Multi-Stage DCF model, have generally remained within the traditional range of five to seven percent.

Q. Has the Commission also recognized the importance of checking the reasonableness of the results produced by the Multi-Stage DCF model?

A. Yes. In a 2007 order for PGE, the Commission indicated that it was important to check the reasonableness of the DCF results by reference to the results of other models, including the CAPM and Risk Premium models, and by comparison to authorized returns in other jurisdictions.[55]

Q. What are the benefits of using the Multi-Stage form of the DCF model?

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

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

A. The Multi-Stage DCF model sets a company's current stock price equal to the present value of future cash flows received over three "stages." In all three stages, cash flows are equal to the annual dividend payments that stockholders receive. Stage One is a short-term growth period that consists of the first five years; Stage Two is a transition period from the short-term growth rate to the long-term growth rate (i.e., years six through 10); and Stage Three is a long-term growth period that begins in year 11 and continues in perpetuity (i.e., year 200). The ROE is then calculated as the rate of

[55] Order No. 07-015 at 47-48.

return that results from the initial stock investment and the dividend payments over the analytical period.

Q. Please summarize the earnings per share (EPS) growth rates used in your Multi-Stage DCF model.

A. As shown in Exhibit PAC/405, I began with the current annualized dividend as of November 29, 2019, for each proxy group company. In the first stage of the model, the current annualized dividend is escalated based on the average of the three- to five-year earnings growth estimates reported by Zacks, Thomson First Call, and Value Line. For the third stage, I relied on long-term projected growth in Gross Domestic Product (GDP). The second stage growth rate is a transition from the first stage growth rate to the long-term growth rate on a geometric average basis.

Q. How did you calculate the long-term GDP growth rate?

A. As shown in Exhibit PAC/406, the long-term growth rate of 5.53 percent is based on real GDP growth rate of 3.22 percent from 1929 through 2018,[56] and a projected inflation rate of 2.23 percent. The projected inflation rate is based on three measures: (1) the average long-term projected growth rate in the Consumer Price Index (CPI) of 2.10 percent;[57] (2) the compound annual growth rate of the CPI for all urban consumers for 2029-2050 of 2.31 percent as projected by the Energy Information Administration (EIA); and (3) the compound annual growth rate of the GDP chain-type price index for 2029–2050 of 2.29 percent, also reported by the EIA.[58]

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[56] U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts Tables, Table 1.1.1, November 27, 2019.

[57] Blue Chip Financial Forecasts, Vol. 38, No. 6, June 1, 2019, at 14.

[58] U.S. Energy Information Administration, Annual Energy Outlook 2019, Table 20, Macroeconomic Indicators.

Q. Do the assumptions used in the Multi-Stage DCF model address the effect of low dividend yields on the DCF results?

A. No, they do not. While the Multi-Stage DCF model provides for changes in growth over time, it does not address the abnormally low dividend yields for utility stocks and the effect of those low dividend yields on the DCF model, specifically the understated ROEs that result from the use of these assumptions. For that reason, I have also considered the results of alternative risk-premium based methodologies, which I will discuss later in my direct testimony.

Discounted Cash Flow Model Results

Q. How did you calculate the range of results for the Constant Growth and Multi-Stage DCF models?

A. I calculated the low result for both DCF models using the minimum growth rate (*i.e.*, the lowest of the First Call, Zacks, and Value Line earnings growth rates) for each of the proxy group companies. Thus, the low result reflects the minimum DCF result for the proxy group. I used a similar approach to calculate the high results, using the highest growth rate for each proxy group company. The mean results were calculated using the average growth rates from all sources.

Q. Have you excluded any of the Constant Growth DCF results for individual companies in your proxy group?

A. Yes, I have. It is appropriate to exclude Constant Growth DCF results below a specified threshold at which equity investors would consider such returns to provide an insufficient return increment above long-term debt costs. The average credit rating for the companies in my proxy group is BBB+/Baa1. The average yield on Moody's

Baa-rated utility bonds for the 30 trading days ending November 29, 2019, was 3.77 percent.[59] As shown in Exhibit PAC/404, I have eliminated Constant Growth DCF results lower than 7.00 percent because such returns would provide equity investors a risk premium only 323 basis points above Baa-rated utility bonds.

Q. Have you considered the results of any other DCF model?

A. Yes, because of analysts' views that utility stocks may currently be at unsustainably high prices, I have also considered the results of a projected Constant Growth DCF model. The projected DCF analysis relies on Value Line's projected average stock prices and dividends for the 2022–2024 period and the five-year projected EPS growth rates. As shown in Exhibit PAC/407, my analysis demonstrates that using the Value Line projected assumptions in the DCF model increases the ROE by 66 basis points (i.e., 9.59 percent vs. 8.93 percent) as compared with the 90-day average Constant Growth DCF results.

Q. What are the results of your DCF analyses?

A. Figure 9 summarizes the results of my DCF analyses. As shown in Figure 9, the mean Constant Growth DCF results range from 8.93 percent to 9.04 percent and the mean high results are in the range of 10.03 percent to 10.10 percent. The mean Multi-Stage DCF results range from 8.93 percent to 9.03 percent and the mean high results are in the range of 9.19 percent to 9.29 percent. While I also summarize the mean low DCF results, I do not believe that the low Constant Growth and Multi-Stage DCF results provide a reasonable spread over the expected yields on Treasury bonds to

[59] Source: Bloomberg Professional.

compensate investors for the incremental risk related to an equity investment. Finally, the projected DCF results ranged from 8.94 percent to 10.41 percent.

Figure 9: Discounted Cash Flow Results

	Mean Low	**Mean**	**Mean High**
Constant Growth DCF[60]			
30-Day Average	8.34%	9.04%	10.10%
90-Day Average	8.32%	8.93%	10.10%
180-Day Average	8.38%	9.01%	10.03%
Multi-Stage DCF[61]			
30-Day Average	8.73%	8.93%	9.19%
90-Day Average	8.73%	8.94%	9.20%
180-Day Average	8.81%	9.03%	9.29%
Projected DCF[62]			
	Mean Low	Mean	Mean High
2022-2024 Projection	8.94%	9.59%	10.41%

Q. What are your conclusions about the results of the DCF models?

A. As discussed previously, one primary assumption of the DCF models is a constant P/E ratio. That assumption is heavily influenced by the market price of utility stocks. To the extent that utility valuations are high and may not be sustainable, it is important to consider the results of the DCF models with caution. The dividend yield on the 30-day average DCF analysis was 3.16 percent, lower than the average dividend yield for electric utilities over the last 10 years. These data points demonstrate that the results of the current DCF models are significantly below more normal market conditions. Therefore, while I have given weight to the results of the

[60] *See* Exhibit PAC/404.
[61] *See* Exhibit PAC/405.
[62] *See* Exhibit PAC/407.

DCF models, my recommendation also gives weight to the results of other ROE estimation models.

CAPM Analysis

Q. Please briefly describe the Capital Asset Pricing Model.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. This second component is the product of the market risk premium and the Beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

K_e = the required market ROE;

β = Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market.

In this specification, the term $(r_m – r_f)$ represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

The variance of the market return (*i.e.*, Variance (r_m)) is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the general market (*i.e.*, Covariance (r_e, r_m)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, Beta represents the risk of the security relative to the general market.

Q. What risk-free rate did you use in your CAPM analysis?

A. I relied on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds of 2.28 percent;[63] (2) the average projected 30-year U.S. Treasury bond yield for Q1 2020 through Q1 2021 of 2.36 percent;[64] and (3) the average projected 30-year U.S. Treasury bond yield for 2021 through 2025 of 3.20 percent.[65]

Q. Would you place more weight on one of these scenarios?

A. Yes. Based on current market conditions, I place more weight on the results of the projected yields on the 30-year Treasury bonds. As discussed previously, the estimation of the cost of equity in this case should be forward looking because it is the return that investors would receive over the future rate period. Therefore, the inputs and assumptions used in the CAPM analysis should reflect the expectations of the market at that time. As discussed above, leading economists surveyed by Blue Chip are expecting an increase in long-term interest rates on government and corporate bonds over the next five years. This is an important consideration for equity investors as they assess their return requirements. While I have included the

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[63] Bloomberg Professional, as of November 29, 2019.
[64] Blue Chip Financial Forecasts, Vol. 38, No. 11, November 1, 2019, at 2.
[65] Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 14.

results of a CAPM analysis that relies on the current average risk-free rate, this analysis fails to take into consideration the effect of the market's expectations for interest rate increases on the cost of equity.

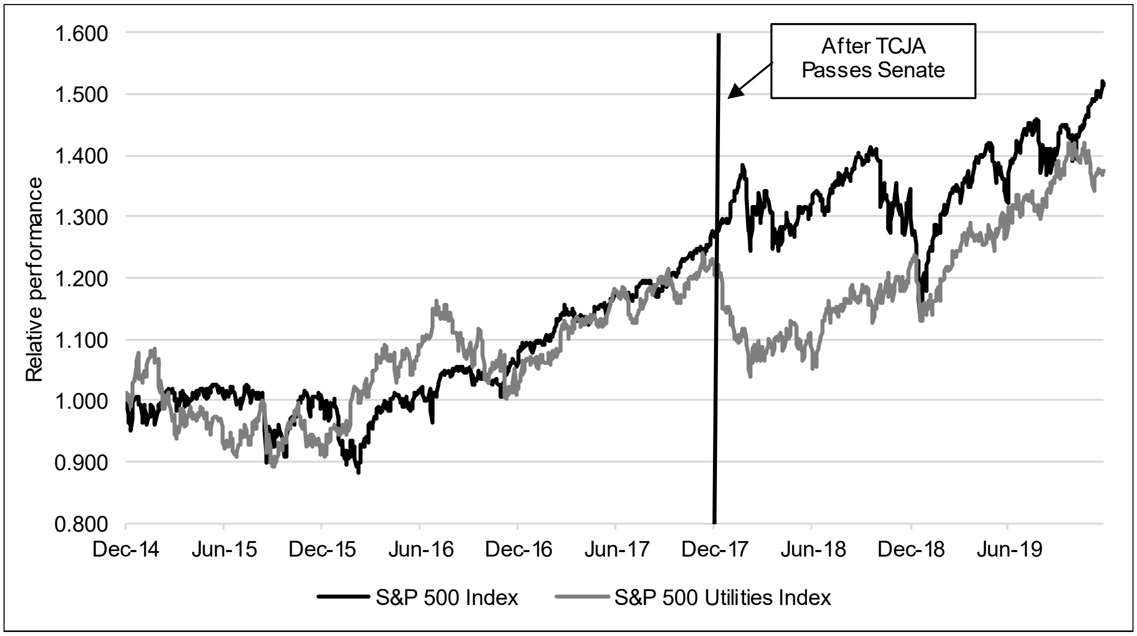
Q. What Beta coefficients did you use in your CAPM analysis?

A. As shown in Exhibit PAC/408 CAPM 1 and Exhibit PAC/408 CAPM 2, I used the Beta coefficients for the proxy group companies as reported by Bloomberg and Value Line. The Beta coefficients reported by Bloomberg were calculated using 10 years of weekly returns relative to the S&P 500 Index. Value Line's calculation is based on five years of weekly returns relative to the New York Stock Exchange Composite Index.

Q. Why did you select a 10-year period to calculate the Beta coefficients from Bloomberg?

A. As I discussed in Section V, the TCJA has had a significant effect on utility companies. While other industries are able to retain the benefits of a reduced corporate income tax rate, this benefit has largely been passed through to customers by utility companies. This fundamental difference affected investors' view of the utility industry relative to other industries. As shown in Figure 10, after the Senate passed the TCJA on December 2, 2017, utilities significantly deviated from the broader market.

Figure 10: Performance of the Utility Industry Relative to the S&P 500[66]



The TCJA's effect on the utility industry relative to other industries caused a significant short-term shift in the returns on the utility industry relative to the broader market. Over the last three-to-five years, volatility for the utility industry has been higher than the broader market (as measured by the S&P 500),[67] suggesting higher beta coefficients for utility companies. However, in short-term calculations of the Beta coefficient, the significant effect of the shift in returns related to the TCJA has outweighed the effect of longer-term measures of relative volatility. As such, to reflect the long-term relationship that suggests utility stocks are less volatile than the broader market (*i.e.* the relative volatility for utility companies has been lower than the S&P 500 over the ten-year measure),[68] I selected a 10-year period to calculate the Beta coefficients from Bloomberg.

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[66] Bloomberg Professional. Data through November 29, 2019.
[67] *See* S&P Dow Jones Indices, Equity, S&P 500 Utilities, February 28, 2019.
[68] *Id.*

Q. How did you estimate the market risk premium in the CAPM?

A. I used two methods to estimate the forward-looking market risk premium. First, I estimated the market risk premium based on the expected return on S&P 500 Index less the yield on the 30-year Treasury bond. The expected total return on the S&P 500 Index is calculated using the Constant Growth DCF model for thecCompanies in the S&P 500 Index. As shown in Exhibit PAC/408 CAPM 3, based on an estimated market capitalization-weighted dividend yield of 1.89 percent and a weighted long-term growth rate of 10.61 percent, the estimated required market return for the S&P 500 Index is 12.60 percent. The implied Market Risk Premiums over the current and projected yields on the 30-year U.S. Treasury bond range from 9.40 percent to 10.32 percent.

Second, as also shown in Exhibit PAC/408 CAPM 3, I used S&P's estimate of five-year earnings growth for the companies in the S&P 500 Index of 11.56 percent and S&P's estimate of the dividend yield on the S&P 500 of 1.90 percent, which produces an implied total return on the S&P 500 of 13.58 percent.[69] Under this method, the implied Market Risk Premiums over current and projected yields on the 30-year U.S. Treasury bond range from 10.38 percent to 11.30 percent.

Q. Have other regulators endorsed the use of a forward-looking market risk premium?

A. Yes. The Staff of the Maine Public Utilities Commission (Maine PUC) have supported the forward-looking market risk premium. In the Bench Analysis in docket 2018-00194 for Central Maine Power Company, docket 2017-00198 for Emera Maine

[69] Standard and Poor's Earnings and Estimates, November 29, 2019.

and docket 2017-00065 for Northern Utilities, the Staff accepted the forward-looking methodology for calculating the market return that was proposed by the companies.[70] In each case, the market return was the expected return for the S&P 500, which was calculated using a Constant Growth DCF model.

Furthermore, the Maine PUC in docket 2017-0198 used the CAPM results calculated by Staff and Emera Maine as a check on the reasonableness of the DCF results in the case and did not dispute the use of the forward-looking market risk premium by the parties (*i.e.*, Staff and Emera Maine).[71]

Q. What are the results of your CAPM analyses?

A. As shown in Figure 11 (*see also* Exhibits PAC/408 CAPM 1 and PAC/408 CAPM 2), my CAPM analyses produces a range of returns from 8.45 percent to 10.04 percent.

Figure 11: CAPM Results

	Bloomberg Beta	Value Line Beta
Market DCF		
Current Risk-Free Rate (2.28%)	9.08%	8.45%
Q1 2020-Q1 2021 Projected Risk-Free Rate	9.11%	8.48%
2021-2025 Projected Risk-Free Rate (3.20%)	9.40%	8.82%
S&P Earnings and Estimate Report		
Current Risk-Free Rate (2.28%)	9.73%	9.03%
Q1 2020-Q1 2021 Projected Risk-Free Rate	9.75%	9.07%
2021-2025 Projected Risk-Free Rate (3.20%)	10.04%	9.40%

[70] Emera Maine, Request for Approval of a Proposed Rate Increase, Docket No. 2017-00198, Bench Analysis at 71-72 (December 21, 2017); Northern Utilities, Inc. d/b/a UNITIL, Request for Approval of Rate Change Pursuant to Section 307, Docket No. 2017-00065, Bench Analysis, at 15-16 (October 6, 2017).

[71] Emera Maine, Request for Approval of Proposed Rate Increase, Docket No. 2017-00198, June 28, 2018, at 41.

Q. Did you consider another form of the CAPM?

A. Yes. In addition to the "traditional" form of the CAPM, I have also considered the "Empirical CAPM" in estimating the cost of equity for PacifiCorp. The ECAPM calculates the product of the Beta coefficient and the market risk premium and applies a weight of 75 percent to that result. The model then applies a 25 percent weight to the market risk premium, without any effect from the Beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [5]$$

where:

k_e = the required market ROE

β = Beta coefficient of an individual security

r_f = the risk-free rate of return

r_m = the required return on the market as a whole

The Empirical form of the CAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low Beta coefficients such as regulated utilities. The ECAPM is not redundant to the use of adjusted Betas; rather, it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[72]

As with the CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on 30-year Treasury securities noted

[72] Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 191.

earlier as the risk-free rate, and the Value Line and Bloomberg beta coefficients. As shown in Figure 12 (*see also* Exhibits PAC/408 CAPM 1 and PAC/408 CAPM 2), my ECAPM analysis produces a range of returns from 9.48 percent to 10.92 percent.

Figure 12: ECAPM Results

	Bloomberg Beta	**Value Line Beta**
Market DCF		
Current Risk-Free Rate (2.28%)	9.96%	9.48%
Q1 2020-Q1 2021 Projected Risk-Free Rate	9.98%	9.51%
2021-2025 Projected Risk-Free Rate (3.20%)	10.20%	9.76%
S&P Earnings and Estimate Report		
Current Risk-Free Rate (2.28%)	10.69%	10.17%
Q1 2020-Q1 2021 Projected Risk-Free Rate	10.71%	10.19%
2021-2025 Projected Risk-Free Rate (3.20%)	10.92%	10.45%

Bond Yield Plus Risk Premium Analysis

Q. Please describe the Bond Yield Plus Risk Premium approach.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as 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 electric utility companies as the historical measure of the cost of equity to determine the risk premium.

Q. Are there other considerations that should be addressed in conducting this analysis?

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 also important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of U.S. Treasury bond yields. Otherwise, if authorized ROEs for electric utilities serve as the measure of required equity returns and the yield on the long-term U.S. Treasury bond serves as the relevant measure of interest rates, the risk premium simply would be the difference between those two points.[73]

Q. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A. Yes. Investors are aware of ROE awards in other jurisdictions, and they consider those awards as a benchmark for a reasonable level of equity return for utilities of comparable risk operating in other jurisdictions. Because my Bond Yield Plus Risk Premium analysis is based on authorized ROEs for electric utility companies relative

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[73] *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.

to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors.

Q. What did your Bond Yield Plus Risk Premium analysis reveal?

A. As shown in Figure 13 below, from 1992 through November 2019, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [5]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

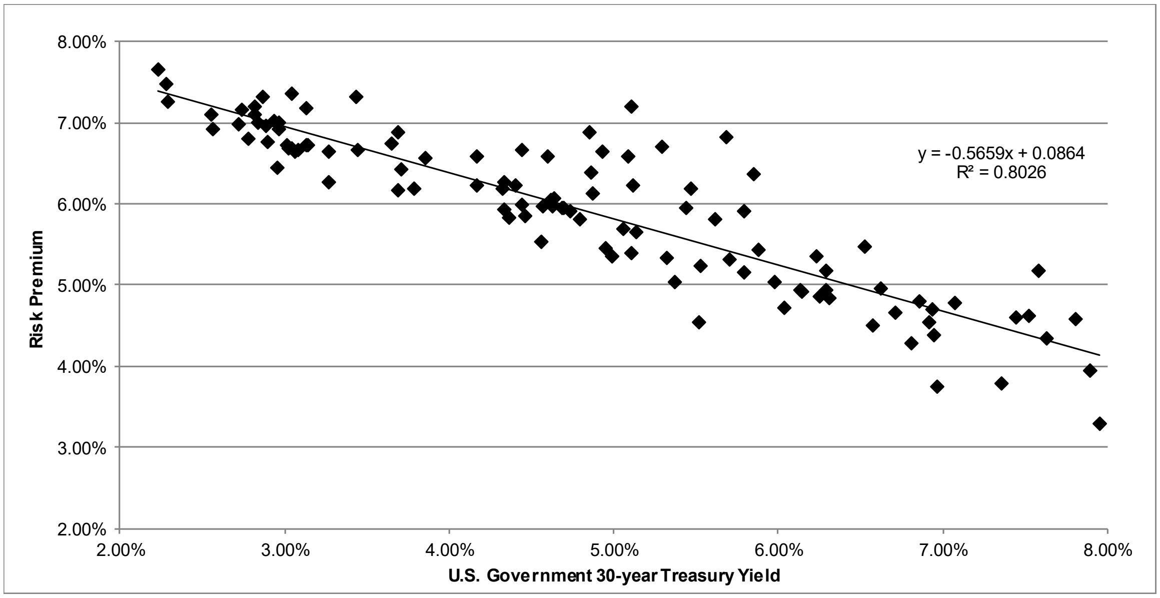
b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding allowed ROEs were derived from 612 integrated electric utility rate cases from 1992 through November 2019 as reported by Regulatory Research Associates (RRA).[74] This equation's coefficients were statistically significant at the 99.00 percent level.

[74] This analysis began with a total of 1,175 cases and was screened to eliminate limited issue rider cases, transmission-only cases, distribution cases and cases that were silent with respect to the authorized ROE. After applying those screening criteria, the analysis was based on data for 612 cases.

Figure 13: Risk Premium Results



As shown in Exhibit PAC/409, based on the current 30-day average of the 30-year U.S. Treasury bond yield (*i.e.*, 2.28 percent), the risk premium would be 7.35 percent, resulting in an estimated ROE of 9.63 percent. Based on the near-term (Q1 2020 – Q1 2021) projections of the 30-year U.S. Treasury bond yield (*i.e.*, 2.36 percent), the risk premium would be 7.31 percent, resulting in an estimated ROE of 9.67 percent. Based on longer-term (2021-2025) projections of the 30-year U.S. Treasury bond yield (*i.e.*, 3.20 percent), the risk premium would be 6.63 percent, resulting in an estimated ROE of 10.03 percent.

Q. How did the results of the Bond Yield Risk Premium inform your recommended ROE for PacifiCorp?

A. I have considered the results of the Bond Yield Risk Premium analysis in setting my recommended ROE for PacifiCorp. The results of my CAPM, ECAPM and Bond Yield Risk Premium analyses provide support for my view that the DCF model is understating investors' return requirements under current market conditions. Also, as noted above, investors will consider the ROE award of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The Risk Premium analysis takes into account this comparison by estimating the return expectations of investors based on the current and past ROE awards of electric utilities across the U.S.

Expected Earnings Analysis

Q. Have you considered any additional analysis to estimate the cost of equity for PacifiCorp?

A. Yes. I have considered an Expected Earnings analysis based on the projected ROEs for each of the proxy group companies.

Q. What is an Expected Earnings Analysis?

A. The Expected Earnings methodology is a comparable earnings analysis that calculates the earnings that an investor expects to receive on the book value of a stock. The Expected Earnings analysis is a forward-looking estimate of investors' expected returns. The use of an Expected Earnings approach based on the proxy companies provides a range of the expected returns on a group of risk comparable companies to the subject company. This range is useful in helping to determine the opportunity cost of investing in the subject company, which is relevant in determining a company's ROE.

Q. How did you develop the Expected Earnings Approach?

A. I relied primarily on the projected ROE for the proxy companies as reported by Value Line for the period from 2022-2024. I then adjusted those projected ROEs to account for the fact that the ROEs reported by Value Line are calculated on the basis of common shares outstanding at the end of the period, as opposed to average shares outstanding over the period. As shown in Exhibit PAC/410, the Expected Earnings analysis results in a mean of 11.10 percent and a median of 10.81 percent.

VIII. REGULATORY AND BUSINESS RISKS

Q. Do the DCF, CAPM, Risk Premium, and Expected Earnings results for the proxy group, taken alone, provide an appropriate estimate of the cost of equity for PacifiCorp?

A. No. These results provide only a range of the appropriate estimate of PacifiCorp's cost of equity. There are several additional factors that must be taken into consideration when determining where the Company's cost of equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

Capital Expenditures

Q. Please summarize PacifiCorp's capital expenditure requirements.

A. PacifiCorp's current projections for 2020 through 2024 include approximately $10.7 billion in capital investments for the period.[75] Based on PacifiCorp's net utility plant of approximately $18 billion as of December 31, 2018,[76] the ratio of projected capital expenditures to net utility plant is approximately 60.00 percent.

Q. How is PacifiCorp's risk profile affected by its capital expenditure requirements?

A. As with any utility facing increased capital expenditure requirements, the Company's

[75] Data is provided for PacifiCorp-wide capital expenditures for the 2020-2024 period.
[76] Id.

risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes. From a credit perspective, the additional pressure on cash flows associated with higher levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[77]

Therefore, to the extent that PacifiCorp's rates do not permit the opportunity to recover its full cost of doing business, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

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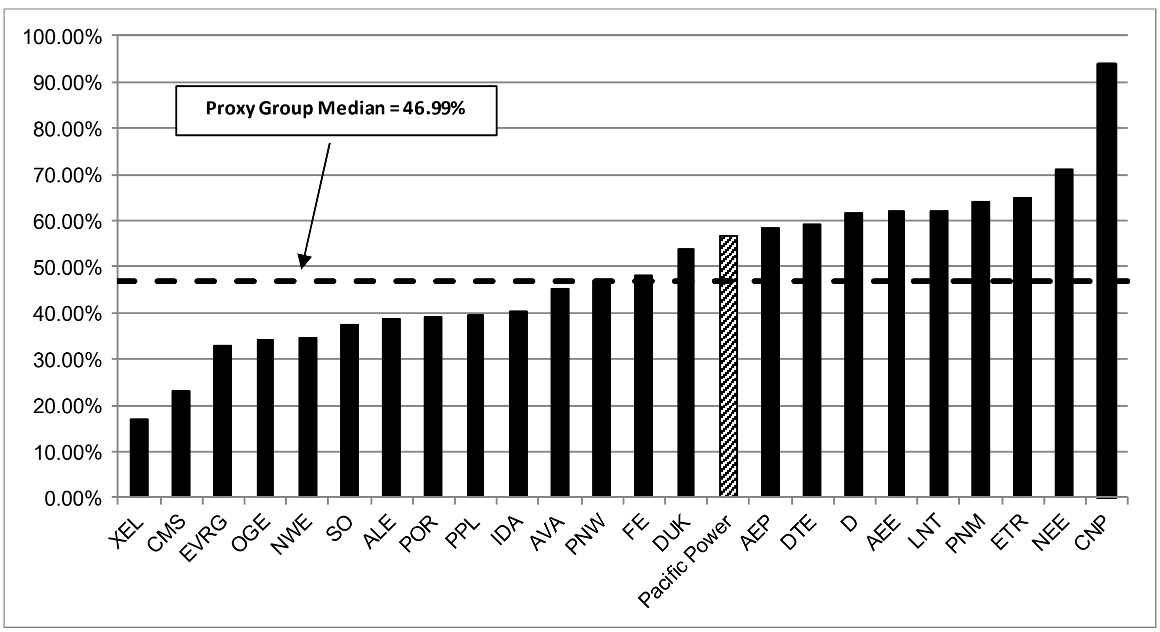
[77] S&P GLOBAL RATINGS, *Assessing U.S. Investor-Owned Utility Regulatory Environments* at 7 (August 10, 2016).

Q. How do PacifiCorp's capital expenditure requirements compare to those of the proxy group companies?

A. As shown in Exhibit PAC/411 CapEx 1, I calculated the ratio of expected capital expenditures to net utility plant for PacifiCorp and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2020-2024 by its total net utility plant as of December 31, 2018. As shown in Exhibit PAC/411 CapEx 2 (*see also* Figure 14 below), PacifiCorp's ratio of capital expenditures as a percentage of net utility plant of 60.00 percent is approximately 1.14 times the median for the proxy group companies of 52.52 percent. This result indicates slightly greater risk relative to the companies in the proxy group.

Figure 14: Comparison of Capital Expenditures – Proxy Group Companies



Q. Does PacifiCorp have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A. Only for certain investments, namely the costs to construct or otherwise acquire renewable generation facilities and the associated transmission. As shown in Exhibit

PAC/411, 52.52 percent of the proxy group utilities recover costs through capital tracking mechanisms.

Q. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A. PacifiCorp's capital expenditure requirements as a percentage of net utility plant are increasing and will continue over the next few years. Additionally, unlike a number of the operating subsidiaries of the proxy group, PacifiCorp does not have a comprehensive capital tracking mechanism to recover projected capital expenditures. Therefore, PacifiCorp's elevated capital expenditure requirements result in a risk profile that is greater than that of the proxy group and supports an ROE toward the higher end of the reasonable range of ROEs.

Regulatory Risk

Q. Please explain how the regulatory environment affects investors' risk assessments.

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory authorities recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of investors and customers. Utilities must finance their operations and require the opportunity to earn a reasonable return on their invested capital to maintain their financial profiles. PacifiCorp is no exception. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

Equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. Please explain how credit rating agencies consider regulatory risk in establishing a company's credit rating.

A. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[78]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[79] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[80]

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[81] Moody's further

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[78] MOODY'S INVESTORS SERVICE, *Rating Methodology: Regulated Electric and Gas Utilities* at 4 (Jun. 23, 2017).
[79] STANDARD & POOR'S 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).
[80] *Id*. at 1.
[81] MOODY'S INVESTORS SERVICE, *Rating Methodology: Regulated Electric and Gas Utilities* at 6 (Jun. 23, 2017).

highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[82]

Q. Have you conducted any analysis of the regulatory framework in Oregon relative to the jurisdictions in which the companies in your proxy group operate?

A. Yes. I have evaluated the regulatory framework in Oregon on five factors that are important in terms of providing a regulated utility an opportunity to earn its authorized ROE. These are: (1) fuel cost recovery; (2) test year convention (*i.e.*, forecast vs. historical); (3) method for determining rate base (*i.e.*, average vs. year-end); (4) use of revenue decoupling mechanisms or other clauses that mitigate volumetric risk; and (5) prevalence of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in Exhibit PAC/412 and summarized below.

Fuel Cost Recovery: PacifiCorp has a Power Cost Adjustment Mechanism (PCAM) to recover power costs. However, while traditional fuel cost recovery mechanisms allow all variances between projected fuel costs and actual fuel costs to be recovered from or refunded to customers, the PCAM for PacifiCorp has a deadband that requires PacifiCorp to absorb some portion of the variation in power costs. If the power cost variation falls within this deadband, there will be no power cost rate adjustment. The PCAM has an asymmetrical deadband, with a negative

[82] Id.

annual power cost variance deadband of $15 million, and a positive annual power cost variance deadband of $30 million. The PCAM also has a sharing mechanism, whereby any power cost variance outside the deadband will be shared 90 percent by customers and 10 percent by PacifiCorp. In addition, under the PCAM, there is an earnings test of +/- 100 basis points around PacifiCorp's authorized ROE. If PacifiCorp is earning within this range of its authorized ROE, there will be no power cost adjustment for that year. Finally, amortization of deferred amounts in any one year under the PCAM is limited to six percent of PacifiCorp's revenues in the preceding calendar year.[83]

As a result, the PCAM does not fully mitigate the power cost risk for PacifiCorp. This is important to investors because fuel and purchased power costs typically account for 50 – 60 percent of the total operating costs for a regulated utility. Moreover, according to SNL Financial, there are only nine states (*i.e.*, Arizona, Hawaii, Idaho, Missouri, Montana, Oregon, Vermont, Washington, and Wyoming) that have fuel cost recovery mechanisms with sharing bands. The remaining 41 states either have restructured and the electric utilities do not own generation or have fuel cost recovery mechanisms with a true-up between actual and forecasted fuel costs.[84]

In addition, 91.23 percent of the operating companies held by the proxy group are allowed to pass through fuel costs and purchased power costs directly to customers, without deadbands, sharing bands and earnings tests.

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[83] *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).
[84] Source: SNL Financial, Commission Profiles as of November 20, 2019.

Test year convention: PacifiCorp is using a fully forecasted test period for the calendar year 2021 with the exception of new plant in-service which is only included through the rate effective date. Likewise, 50.00 percent of the operating companies held by the proxy group provide service in jurisdictions that use a fully or partially forecast test year.

Rate Base: The Company's rate base in this proceeding is based on December 2020 year end for plant-related balances and 2021 average rate base for all other balances. In contrast, the majority (*i.e.*, 51.75 percent) of the operating subsidiaries held by the proxy group are allowed to use year-end rate base, meaning that the rate base includes capital additions that occurred in the second half of the test year and is more reflective of net utility plant going forward.

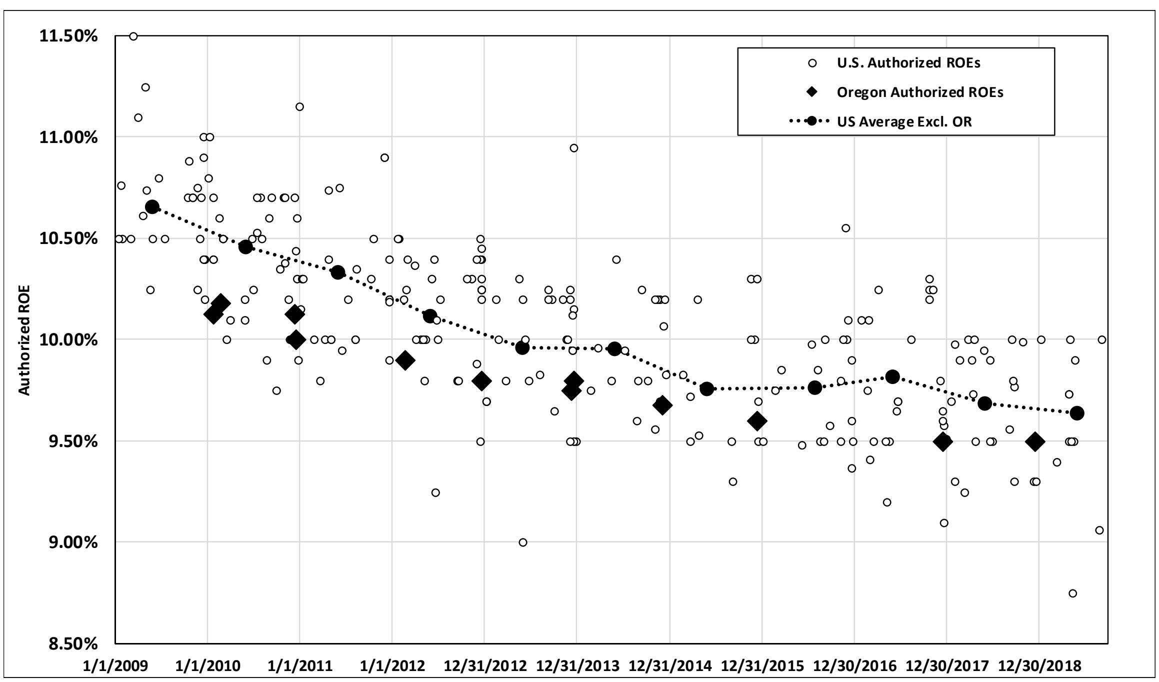
Volumetric Risk: PacifiCorp does not have protection against volumetric risk in Oregon. In contrast, 52.63 percent of the operating companies held by the proxy group have some form of protection against volumetric risk through either a partial or full revenue decoupling mechanism that mitigates the effect of fluctuations in volume on revenues.

Capital Cost Recovery: PacifiCorp is authorized to separately file to recover capital costs to construct or otherwise acquire renewable generation facilities and the associated transmission. However, utilities in Oregon are prohibited by law from the inclusion of construction work in progress in rate base, and deferred accounting is not available for recovery of capital expenditures. By comparison, 55.26 percent of the operating companies held by the proxy group also have some form of capital cost recovery mechanism in place that allows for recovery of capital costs between rate cases.

Q. How do recent returns in Oregon compare to the authorized returns in other jurisdictions?

A. As noted in RRA's evaluation above, the authorized ROEs for electric and natural gas utilities in Oregon, while largely the result of settlement agreements approved by the Commission, have been below the prevailing industry average for electric and natural gas utilities across the U.S. Figure 15 below shows the authorized returns for vertically integrated electric utilities in other jurisdictions since January 2009, and the returns authorized in Oregon for electric companies. As shown in Figure 15, the authorized returns for electric utilities in Oregon have been at the low end of the range of authorized ROEs in other state jurisdictions for 2009 through 2019.

Figure 15: Comparison of Oregon and U.S. Authorized Electric Returns



Q. Is there any reason that the Commission should be concerned about authorizing equity returns that are at the low end of the range established by other state regulatory jurisdictions?

A. Yes. Credit rating agencies take the authorized ROE into consideration in the overall risk analysis of a company. Therefore, to the extent that the returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the company operates. For example, Moody's recently downgraded ALLETE, Inc. from A3 to Baa1 for reasons that included the less than favorable outcome in Minnesota Power's last rate case in Minnesota. Moody's viewed Minnesota Power's recent rate case decision as credit negative for reasons which included: (1) the below average authorized ROE of 9.25 percent which resulted in a reduction of approximately $20 million between the requested and approved revenue requirement; (2) the disallowance of certain expenses such as prepaid pension expenses; and (3) the decision to not adopt the annual rate review mechanism, which if adopted would have mitigated the effect of industrial customers scaling back production in response to changes in economic conditions.[85] PacifiCorp must compete for capital with other utilities and businesses. Placing PacifiCorp at the lower end of authorized ROEs outside Oregon over the longer term could negatively impact its access to capital.

[85] MOODY'S INVESTORS SERVICE, *Credit Opinion: ALLETE, Inc. Update following downgrade* at 3 (April 3, 2019).

Q. How should the Commission use the information regarding authorized ROEs in other jurisdictions in determining the ROE for PacifiCorp?

A. As discussed above, the companies in the proxy group operate in multiple jurisdictions across the U.S. Since PacifiCorp must compete directly for capital with investments of similar risk, it is appropriate to review the authorized ROEs in other jurisdictions. The comparison is important because investors are considering the authorized returns across the U.S. and are likely to invest equity in those utilities with the highest returns. Furthermore, investors are also likely to consider business and financial risks for a company like PacifiCorp which faces increased risk as a result of the company's capital expenditure plan and limited cost recovery mechanisms. Therefore, authorizing an ROE for PacifiCorp that is equivalent to the average authorized ROE for other vertically integrated electric utilities is not sufficient to compensate investors for the added risk of PacifiCorp. As such, it is important that the Commission consider, as I have in my recommendation, the additional risk of PacifiCorp and place the authorized ROE for PacifiCorp towards the high end of authorized ROEs for other vertically integrated electric utilities.

Q. What are your conclusions regarding the perceived risks related to the Oregon regulatory environment?

A. As discussed throughout this section of my testimony, both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Considering the regulatory adjustment mechanisms, many of the companies in the proxy group have more timely cost recovery through fuel cost recovery mechanisms, fully forecasted test years, year-end rate base in all cases, capital cost recovery trackers, and revenue stabilization mechanisms than PacifiCorp has in Oregon. Additionally, authorized ROEs in Oregon have been below the average authorized ROEs for electric and gas utilities across the U.S. For these reasons, I conclude that the authorized ROE for PacifiCorp should be higher than the proxy group mean.

Generation Ownership

Q. How does the business risk of vertically integrated electric utilities compare to the business risk of other regulated utilities?

A. According to Moody's, generation ownership causes vertically integrated electric utilities to have higher business risk than either electric transmission and distribution companies, or natural gas distribution or transportation companies.[86] As a result of this higher business risk, integrated electric utilities typically require a higher ROE or percentage of equity in the capital structure than other electric or gas utilities.

Q. Are there other risk factors specific to vertically integrated electric utilities that the credit rating agencies consider when determining the credit rating of a company that owns generation?

A. Yes. As discussed above, Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. The third factor diversification, which Moody's assigns a 10.00 percent weighting in the

[86] MOODY'S INVESTORS SERVICE, *Rating Methodology: Regulated Electric and Gas Utilities* at 21-22 (June 23, 2017).

overall assessments of a company's business risk, considers the fuel source diversity of a utility with generation. Moody's notes:

> For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.
>
> For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.[87]

Q. Has Oregon enacted legislative requirements related to renewable energy?

A. Yes. As described in PacifiCorp's 2018 Form 10-K, the Oregon Renewable Energy Act (OREA) provides a comprehensive renewable energy policy and renewable portfolio standard (RPS) for Oregon. Subject to certain exemptions and cost limitations established in the law, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least five percent in 2011 through 2014, 15 percent in 2015 through 2019, and 20 percent in 2020 through 2024. In March 2016, Oregon Senate Bill (SB) 1547, the Clean Electricity and Coal Transition Plan, was signed into law. SB 1547 requires that coal-fueled resources are eliminated from Oregon's allocation of electricity by January 1, 2030, and increases the current RPS target from 25 percent in

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[87] *Id.* at 16.

2025 to 50 percent by 2040. SB 1547 also implements new renewable energy certificate banking provisions, as well as the following interim RPS targets: 27 percent in 2025 through 2029, 35 percent in 2030 through 2034, 45 percent in 2035 through 2039, and 50 percent by 2040 and subsequent years. As required by the OREA, the Commission has approved an automatic adjustment clause to allow an electric utility, including PacifiCorp, to recover prudently incurred costs of its investments in renewable energy generating facilities and associated transmission costs.

Q. Is a transition to renewable resources supported by all regulatory jurisdictions where PacifiCorp operates?

A. No, it is not. Currently SB 1547 is in conflict with legislation that has been passed in Wyoming, Senate File (SF) 159. While the Oregon legislation seeks to transition from coal to renewable resources, Wyoming SF159 would require the Company to attempt to sell any generating assets that it intends to retire before it could request recovery of the costs of replacement generating assets. In addition, the legislation requires that the Company enter into a purchase power agreement to repurchase the power from the coal facility. While the rulemaking associated with Wyoming SF159 is still in discussion, the conflict between the Oregon and Wyoming legislation creates risk for the Company that is not uniformly represented in the proxy group companies.

Q. Have you conducted an analysis to compare the fuel sources for the generation portfolio of PacifiCorp to the companies in your proxy group?

A. Yes, I have. Specifically, I calculated for PacifiCorp, and each company in the proxy group, the percentage of regulated owned generation capacity that was derived from one of the following fuel sources: oil/natural gas, coal, nuclear, hydro, and other. As shown in Figure 16, approximately 52.47 percent of PacifiCorp's regulated, owned generation came from coal-fired power plants with approximately 79.20 percent coming from either oil, natural gas, or coal-fired power plants. Therefore, PacifiCorp is more reliant on a limited number of fuel sources for its regulated generation and overall slightly less diversified than the companies in the proxy group.

Figure 16: Regulated Owned Generation Capacity - Fuel Mix for PacifiCorp and Proxy Group

Company	Oil & Natural Gas	Coal	Nuclear	Hydro	Other	Total Generation
Avista Corporation	33.60%	10.41%	0.00%	53.55%	2.43%	100.00%
IDACORP, Inc.	21.36%	26.43%	0.00%	52.20%	0.00%	100.00%
ALLETE, Inc.	5.37%	49.92%	0.00%	7.51%	37.20%	100.00%
NorthWestern Corporation	24.67%	32.54%	0.00%	33.01%	9.78%	100.00%
Dominion Energy, Inc.	49.76%	16.97%	21.47%	10.19%	1.61%	100.00%
Portland General Electric Company	48.74%	20.81%	0.00%	12.14%	18.30%	100.00%
PNM Resources, Inc.	40.19%	34.59%	18.54%	0.00%	6.68%	100.00%
CMS Energy Corporation	52.94%	23.18%	0.00%	19.59%	4.29%	100.00%
Duke Energy Corporation	48.36%	27.95%	16.66%	6.39%	0.64%	100.00%
Xcel Energy Inc.	45.49%	32.85%	8.83%	2.81%	10.03%	100.00%
DTE Energy Company	27.64%	50.70%	9.78%	8.58%	3.30%	100.00%
Southern Company	46.11%	32.58%	11.64%	9.11%	0.57%	100.00%
Pinnacle West Capital Corporation	53.85%	25.20%	17.55%	0.00%	3.40%	100.00%
PacifiCorp	26.71%	52.47%	0.00%	10.71%	10.11%	100.00%
Entergy Corporation	68.26%	13.07%	18.34%	0.33%	0.01%	100.00%
Ameren Corporation	31.36%	49.97%	11.14%	7.35%	0.18%	100.00%
Alliant Energy Corporation	50.76%	32.27%	0.00%	0.84%	16.13%	100.00%
NextEra Energy, Inc.	76.20%	8.56%	11.46%	0.00%	3.78%	100.00%
Evergy, Inc.	34.96%	50.00%	10.03%	0.05%	4.96%	100.00%
American Electric Power Company, Inc.	34.84%	51.92%	9.53%	3.61%	0.10%	100.00%
FirstEnergy Corp.	0.00%	88.89%	0.00%	11.11%	0.00%	100.00%
OGE Energy Corp.	55.16%	37.97%	0.00%	0.00%	6.86%	100.00%
PPL Corporation	36.56%	61.74%	0.00%	1.58%	0.12%	100.00%
CenterPoint Energy, Inc.	19.36%	80.16%	0.00%	0.00%	0.48%	100.00%

Q. Is PacifiCorp's generation portfolio currently in a state of transition?

A. Yes. As further discussed in the testimonies of Mr. Stefan A. Bird and of Ms. Etta Lockey, the Company is responding to changing market conditions and, as indicated by the 2019 Integrated Resource Plan (IRP) action plan, is taking near term actions to retire certain coal units, invest in new renewable generation, and invest in associated transmission.

Q. How does PacifiCorp's generation investment plan affect its business risk?

A. The Company's 2019 IRP action plan includes a significant investment in building transmission and adding new wind and solar generation. This significant investment in transmission and renewable energy will require continued access to capital markets, which highlights the importance of granting PacifiCorp an allowed ROE and equity ratio that is sufficient to attract capital at reasonable terms.

Q. What are your conclusions regarding the perceived risks related to the fuel mix of PacifiCorp's generation portfolio?

A. PacifiCorp's coal-fired generation is subject to increased environmental regulations aimed at cutting power plant emissions. The environmental regulations pose additional business risk as sizable future capital expenditures may be required to comply with regulations. Furthermore, the Company recently outlined plans for reshaping its generation portfolio. While the Company intends to improve fuel diversity over the long-run, the plans will require continued access to capital markets to finance the new investments. The Company's existing generation portfolio and proposed transmission and generation investment plans increase the overall risk profile as compared with the proxy group.

IX. CAPITAL STRUCTURE

Q. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A. Yes. Assuming other factors equal, a higher debt ratio increases the risk to investors. For debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders. Common shareholders are the residual claimants on the cash flow of the company. Therefore, the greater the debt service requirement, the less cash flow available for common equity holders.

Q. What is PacifiCorp's proposed capital structure?

A. As described by PacifiCorp witness Ms. Nikki L. Kobliha, PacifiCorp's proposed capital structure for ratemaking purposes consists of 53.52 percent common equity, 46.47 percent long-term debt and 0.01 percent preferred equity.

Q. Did you conduct any analysis to determine if this requested equity ratio was reasonable?

A. Yes, I did. I reviewed the Company's historical actual capital structure and the capital structures of the utility operating subsidiaries of the proxy companies. Because the ROE is set based on the return that is derived from the risk-comparable proxy group, it is reasonable to look to the proxy group average capital structure to benchmark the equity ratio for the Company.

Q. Please discuss your analysis of the capital structures of the proxy group companies.

A. I calculated the mean proportions of common equity, long-term debt, short-term debt and preferred equity over the most recent eight quarters[88] for each of the companies in the proxy group at the operating subsidiary level. My analysis of the capital structures of the proxy group companies is provided in Exhibit PAC/413. As shown in that Exhibit, the equity ratios for the proxy group at the operating utility company level ranged from 39.98 percent to 61.54 percent with an average of 52.43 percent. PacifiCorp's proposed equity ratio of 53.52 percent approximates the average equity ratio for the proxy group and is well below the high end of the range of equity ratios for the utility operating subsidiaries. Therefore, I conclude that PacifiCorp's proposed capital structure is reasonable.

Q. Are there other factors to be considered in setting the company's capital structure?

A. Yes. The credit rating agencies' response to the TCJA must also be considered when determining the equity ratio. As discussed previously in my testimony, all three rating agencies have noted that the TCJA has negative implications for utility cash flows. S&P and Fitch have specifically identified increasing the equity ratio as one approach to ensure that utilities have sufficient cash flows following the tax cuts and the loss of bonus depreciation. Furthermore, Moody's unprecedented downgrade of

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[88] The source data for this analysis is the operating company data provided in Federal Energy Regulatory Commission Form 1 reports. Due to the timing of those filings, my average capital structure analysis uses the quarterly capital structures reported for the proxy group companies for the period from the fourth quarter of 2017 through the third quarter of 2019.

the rating outlook for the entire utilities sector in June 2018 stresses the importance of maintaining adequate cash flow metrics for the industry as a whole and PacifiCorp in the context of this proceeding.

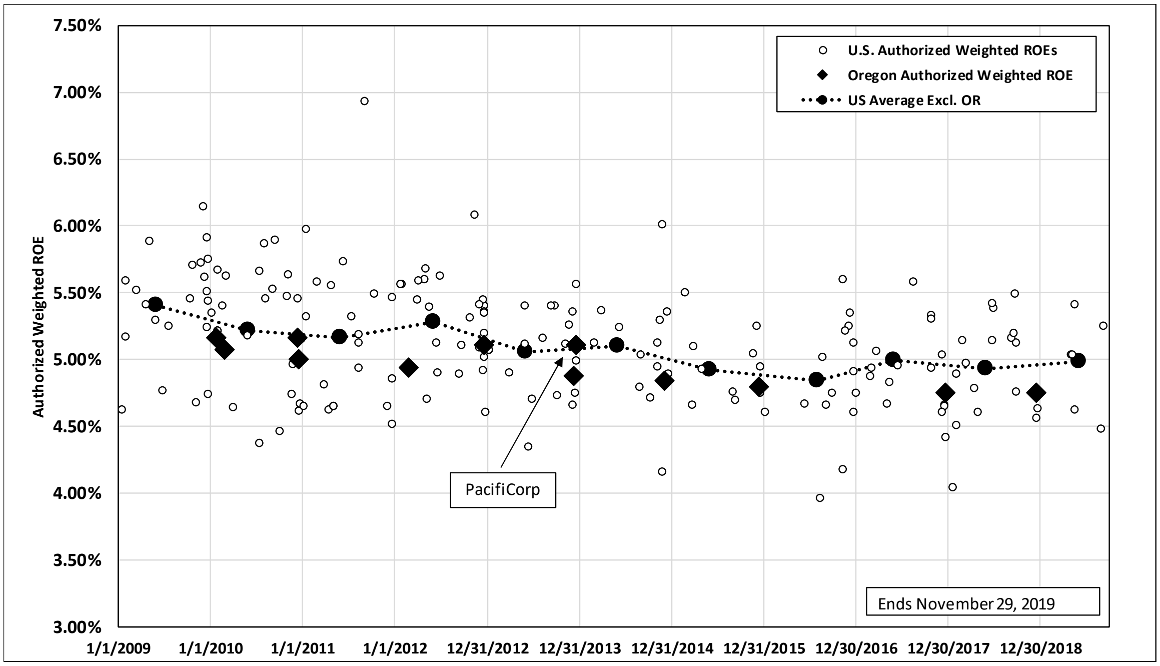
Q. Is there a relationship between the equity ratio and the authorized ROE?

A. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility such as PacifiCorp. To the extent the equity ratio is reduced, it is necessary to increase the authorized ROE to compensate investors for the greater financial risk associated with a lower equity ratio.

Q. Have you conducted an analysis to examine how the Commission's recent authorized equity ratios and authorized ROEs compare to those authorized in other jurisdictions?

A. Yes. As shown in Figure 17, I compared the authorized WROEs (*i.e.*, authorized ROE times the authorized equity ratio) for integrated electric utilities in Oregon to the authorized WROEs in other jurisdictions since January 2009. As shown in Figure 17, the authorized WROEs for integrated electric utilities in Oregon have been somewhat lower than the nationwide average of WROEs authorized by state jurisdictions.

Figure 17: Comparison of Oregon and U.S. Authorized Weighted Equity Ratios for Electric Utilities[89]



Q. Is it appropriate to consider the WROE that has been authorized in other jurisdictions when considering the appropriate equity ratio for Oregon?

A. Yes. One of the most important principles in determining the ROE for a company is to ensure the company has the opportunity to earn a reasonable return on capital that is consistent with the returns available on investments of comparable risk. While it is referenced most often in the discussion of the appropriate ROE, it is equally as important to consider the equity ratio. It is the combination of the equity ratio and the authorized ROE that defines the return to investors. Therefore, the Commission must consider the equity ratio as well as the authorized ROE in establishing a risk-comparable return.

[89] Rate cases in Arkansas, Florida, Indiana, and Michigan have been excluded from Figure 17 since the authorized capital structure approved in the cases includes deferred taxes and other credits at zero or low cost. The additional items have the effect of reducing both the equity and debt ratios used to establish the rate of return which, in turn, produces results that are not comparable to allowed equity ratios in other states.

Q. What is your conclusion regarding an appropriate capital structure for PacifiCorp?

A. Considering the actual capital structures of the proxy group operating companies, I believe that PacifiCorp's proposed common equity ratio of 53.52 percent is reasonable. The proposed equity ratio is well within the range established by the capital structures of the utility operating subsidiaries of the proxy companies and approximates the average. In addition, it is reasonable to rely on a higher equity ratio than the company may have relied on in prior cases as a result of: (a) the cash flow concerns raised by credit rating agencies as a result of the TCJA; and (b) the Company's above average business risk profile as compared to the proxy group. The proposed equity ratio in combination with my recommended ROE are reasonable and would be adequate to support capital attraction on reasonable terms.

X. CONCLUSIONS AND RECOMMENDATION

Q. What is your conclusion regarding a fair ROE for PacifiCorp?

A. Based on the analytical results discussed throughout my direct testimony, and summarized in Figure 18, below, I believe a range from 9.75 percent to 10.25 percent is reasonable. Within that range, an authorized return of 10.20 percent is reasonable for PacifiCorp. This recommendation reflects the range of results for the proxy group companies, the relative business, financial, and regulatory risk of PacifiCorp's electric operations in Oregon as compared to the proxy group, and current capital market conditions. This ROE would enable the company to maintain its financial integrity and therefore its ability to attract capital at reasonable terms under a variety of economic and financial market conditions, while continuing to provide safe, reliable and affordable electric utility service to customers in Oregon.

Figure 18: Summary of Analytical Results

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.34%	9.04%	10.10%
90-Day Average	8.32%	8.93%	10.10%
180-Day Average	8.38%	9.01%	10.03%
Constant Growth Average	8.34%	8.99%	10.08%
Multi-Stage DCF			
First-Stage Growth	Mean Low	Mean	Mean High
30-Day Average	8.73%	8.93%	9.19%
90-Day Average	8.73%	8.94%	9.20%
180-Day Average	8.81%	9.03%	9.29%
Multi-Stage Average	8.76%	8.97%	9.23%
Projected DCF			
	Mean Low	Mean	Mean High
2022-2024 Projection	8.94%	9.59%	10.41%
CAPM			
	Current 30-day Average	Near-Term Blue	Long-Term Blue
Calculated Return on the S&P 500 Companies			
Value Line Beta	8.45%	8.48%	8.82%
Bloomberg Beta	9.08%	9.11%	9.40%
S&P Implied Return on the S&P 500			
Value Line Beta	9.03%	9.07%	9.40%
Bloomberg Beta	9.73%	9.75%	10.04%
ECAPM			
Calculated Return on the S&P 500 Companies			
Value Line Beta	9.48%	9.51%	9.76%
Bloomberg Beta	9.96%	9.98%	10.20%
S&P Implied Return on the S&P 500			
Value Line Beta	10.17%	10.19%	10.45%
Bloomberg Beta	10.69%	10.71%	10.92%

Treasury Yield Plus Risk Premium			
	Current 30-day Average	Near-Term Blue	Long-Term Blue
Risk Premium Analysis	9.63%	9.67%	10.03%
Risk Premium Mean Result	9.77%		
Expected Earnings Analysis			
	Mean		Median
Expected Earnings Result	11.10%		10.81%

Q. What is your conclusion with respect to PacifiCorp's proposed capital structure?

A. My conclusion is that PacifiCorp's proposal to establish a capital structure consisting of 53.52 percent common equity, 46.47 percent long-term debt, and 0.01 percent preferred equity is reasonable when compared to the capital structures of the operating utility companies in the proxy group and taking in consideration the impact of the TCJA on the cash flows of PacifiCorp, and therefore should be adopted.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/401
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Resume and Testimony Listing of Ann E. Bulkley

February 2020

ANN E. BULKLEY

Senior Vice President

Ms. Bulkley has more than two decades of management and economic consulting experience in the energy industry. Ms. Bulkley has extensive state and federal regulatory experience on both electric and natural gas issues including rate of return, cost of equity and capital structure issues. Ms. Bulkley has provided expert testimony on the cost of capital in more than 30 regulatory proceedings before regulatory commissions in Arizona, Arkansas, Colorado, Connecticut, Kansas, Massachusetts, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, South Dakota, West Virginia, and the Federal Energy Regulatory Commission. In addition, Ms. Bulkley has prepared and provided supporting analysis for at least forty Federal and State regulatory proceedings. In addition, Ms. Bulkley has worked on acquisition teams with investors seeking to acquire utility assets, providing valuation services including an understanding of regulation, market expected returns, and the assessment of utility risk factors. Ms. Bulkley has assisted clients with valuations of public utility and industrial properties for ratemaking, purchase and sale considerations, ad valorem tax assessments, and accounting and financial purposes. In addition, Ms. Bulkley has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring and regulatory and litigation support. Prior to joining Concentric, Ms. Bulkley held senior expertise-based consulting positions at several firms, including Reed Consulting Group and Navigant Consulting, Inc. where she specialized in valuation. Ms. Bulkley holds an M.A. in economics from Boston University and a B.A. in economics and finance from Simmons College. Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Analysis and Ratemaking

Ms. Bulkley has provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking. Specific services have included: 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; and many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation).

Cost of Capital

Ms. Bulkley has provided expert testimony on the cost of capital in more than 30 regulatory proceedings before regulatory commissions in Arizona, Arkansas, Colorado, Connecticut, Kansas, Massachusetts, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, South Dakota, West Virginia, and the Federal Energy Regulatory Commission. In addition, Ms. Bulkley has prepared and provided supporting analysis for at least forty Federal and State regulatory proceedings in which she did not testify.

Valuation

Ms. Bulkley has 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. Ms. Bulkley's appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Northern Indiana Fuel and Light: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Kokomo Gas: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- 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.
- 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, a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- 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.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

Ratemaking

Ms. Bulkley has 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. Analyzed and evaluated rate application. Attended hearings and conducted investigation of rate application for regulatory staff. Prepared, supported and defended recommendations for revenue requirements and rates for the company. Developed rates for gas utility for transportation program and ancillary services.

Strategic and Financial Advisory Services

Ms. Bulkley has 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.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Senior Vice President
Vice President
Assistant Vice President
Project Manager

Navigant Consulting, Inc. (1995 – 2002)
Project Manager

Cahners Publishing Company (1995)
Economist

EDUCATION

Boston University
M.A., Economics, 1995

Simmons College
B.A., Economics and Finance, 1991

CERTIFICATIONS

Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
Colorado Public Utilities Commission				
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
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	8/19	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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Indiana Utility Regulatory Commission				
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
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
Kansas Corporation Commission				
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-00194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Rate Case
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast

Michigan Public Service Commission				
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
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.	9/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
New Hampshire Public Utilities Commission				
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR1912XXXX	Return on Equity
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity

Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity
New Mexico Public Regulation Commission				
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
New York State Electric and Gas Company Rochester Gas and Electric	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	Gas 17-G-0460 Electric 17-E-0459	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
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

Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
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
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

Docket No. UE 374
Exhibit PAC/402
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Summary of Results

February 2020

SUMMARY OF ROE ANALYSES RESULTS[1]

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.34%	9.04%	10.10%
90-Day Average	8.32%	8.93%	10.10%
180-Day Average	8.38%	9.01%	10.03%
Constant Growth Average	8.34%	8.99%	10.08%
Multi-Stage DCF			
First-Stage Growth	Mean Low	Mean	Mean High
30-Day Average	8.73%	8.93%	9.19%
90-Day Average	8.73%	8.94%	9.20%
180-Day Average	8.81%	9.03%	9.29%
Multi-Stage Average	8.76%	8.97%	9.23%
Projected DCF			
	Mean Low	Mean	Mean High
2022-2024 Projection	8.94%	9.59%	10.41%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Calculated Return on the S&P 500 Companies			
Value Line Beta	8.45%	8.48%	8.82%
Bloomberg Beta	9.08%	9.11%	9.40%
S&P Implied Return on the S&P 500			
Value Line Beta	9.03%	9.07%	9.40%
Bloomberg Beta	9.73%	9.75%	10.04%
ECAPM			
Calculated Return on the S&P 500 Companies			
Value Line Beta	9.48%	9.51%	9.76%
Bloomberg Beta	9.96%	9.98%	10.20%
S&P Implied Return on the S&P 500			
Value Line Beta	10.17%	10.19%	10.45%
Bloomberg Beta	10.69%	10.71%	10.92%
Treasury Yield Plus Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Analysis	9.63%	9.67%	10.03%
Risk Premium Mean Result	9.77%		
Expected Earnings Analysis			
	Mean		Median
Expected Earnings Result	11.10%		10.81%

Notes:

[1] The analytical results included in the table reflect the results of the Constant Growth, Multi-Stage and Projected DCF analyses excluding the results for individual companies that did not meet the minimum threshold of 7 percent.

Docket No. UE 374
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Proxy Group Selection

February 2020

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
CenterPoint Energy, Inc.	CNP	Yes	BBB+	Yes	Yes	Yes	80.16%	94.6%	67.4%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	Yes	Yes	23.18%	93.8%	74.2%	No
Dominion Resources, Inc.	D	Yes	BBB+	Yes	Yes	Yes	16.97%	95.2%	65.7%	No
DTE Energy Company	DTE	Yes	BBB+	Yes	Yes	Yes	50.70%	92.8%	80.5%	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
FirstEnergy Corporation	FE	Yes	BBB	Yes	Yes	Yes	88.89%	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
OGE Energy Corporation	OGE	Yes	BBB+	Yes	Yes	Yes	37.97%	99.5%	100.0%	No
Otter Tail Corporation	OTTR	Yes	BBB	Yes	Yes	Yes	66.95%	73.5%	100.0%	No
Pinnacle West Capital Corporation	PNW	Yes	A-	Yes	Yes	Yes	25.20%	100.0%	100.0%	No
PNM Resources, Inc.	PNM	Yes	BBB+	Yes	Yes	Yes	34.59%	100.0%	100.0%	No
Portland General Electric Company	POR	Yes	BBB+	Yes	Yes	Yes	20.81%	100.0%	100.0%	No
PPL Corporation	PPL	Yes	A-	Yes	Yes	Yes	61.74%	100.0%	95.8%	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, 2017 & 2016
[9] SNL Financial News Releases

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Constant Growth Discounted Cash Flow Model

February 2020

30-DAY CONSTANT GROWTH DCF -- PACIFICORP PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] All Proxy Group	[10] All Proxy Group	[11] All Proxy Group	[12] With Exclusions	[13] With Exclusions	[14] With Exclusions
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.35	$82.86	2.84%	2.93%	6.00%	7.00%	7.20%	6.73%	8.92%	9.67%	10.14%	8.92%	9.67%	10.14%
Alliant Energy Corporation	LNT	$1.42	$52.75	2.69%	2.77%	6.50%	5.00%	5.50%	5.67%	7.76%	8.43%	9.28%	7.76%	8.43%	9.28%
Ameren Corporation	AEE	$1.90	$75.74	2.51%	2.58%	6.50%	4.70%	6.20%	5.80%	7.27%	8.38%	9.09%	7.27%	8.38%	9.09%
American Electric Power Company, Inc.	AEP	$2.80	$91.90	3.05%	3.13%	4.00%	5.90%	5.60%	5.17%	7.11%	8.29%	9.04%	7.11%	8.29%	9.04%
Avista Corporation	AVA	$1.55	$47.34	3.27%	3.33%	3.50%	3.50%	3.40%	3.47%	6.73%	6.80%	6.83%			
CenterPoint Energy, Inc.	CNP	$1.15	$27.47	4.19%	4.33%	12.50%	3.63%	4.80%	6.98%	7.89%	11.31%	16.95%	7.89%	11.31%	16.95%
CMS Energy Corporation	CMS	$1.53	$61.94	2.47%	2.56%	7.00%	7.50%	6.40%	6.97%	8.95%	9.52%	10.06%	8.95%	9.52%	10.06%
Dominion Resources, Inc.	D	$3.67	$82.08	4.47%	4.59%	6.50%	4.41%	4.80%	5.24%	8.98%	9.83%	11.12%	8.98%	9.83%	11.12%
DTE Energy Company	DTE	$3.78	$124.95	3.03%	3.11%	5.50%	4.83%	6.00%	5.44%	7.93%	8.55%	9.12%	7.93%	8.55%	9.12%
Duke Energy Corporation	DUK	$3.78	$91.21	4.14%	4.25%	6.00%	4.65%	4.80%	5.15%	8.89%	9.40%	10.27%	8.89%	9.40%	10.27%
Entergy Corporation	ETR	$3.72	$117.56	3.16%	3.22%	0.50%	Negative	7.00%	3.75%	3.67%	6.97%	10.28%			10.28%
Evergy, Inc.	EVRG	$2.02	$63.69	3.17%	3.28%	NMF	6.70%	6.40%	6.55%	9.67%	9.83%	9.98%	9.67%	9.83%	9.98%
FirstEnergy Corporation	FE	$1.52	$47.44	3.20%	3.30%	6.50%	Negative	6.00%	6.25%	9.30%	9.55%	9.81%	9.30%	9.55%	9.81%
IDACORP, Inc.	IDA	$2.68	$105.93	2.53%	2.57%	3.50%	2.50%	3.80%	3.27%	5.06%	5.84%	6.38%			
NextEra Energy, Inc.	NEE	$5.00	$231.81	2.16%	2.25%	10.50%	7.99%	8.00%	8.83%	10.23%	11.08%	12.77%	10.23%	11.08%	12.77%
NorthWestern Corporation	NWE	$2.30	$71.47	3.22%	3.27%	3.00%	3.20%	2.70%	2.97%	5.96%	6.23%	6.47%			
OGE Energy Corporation	OGE	$1.55	$42.84	3.62%	3.71%	6.50%	3.50%	4.50%	4.83%	7.18%	8.54%	10.24%	7.18%	8.54%	10.24%
Otter Tail Corporation	OTTR	$1.40	$51.99	2.69%	2.79%	5.00%	9.00%	7.00%	7.00%	7.76%	9.79%	11.81%	7.76%	9.79%	11.81%
Pinnacle West Capital Corporation	PNW	$3.13	$89.87	3.48%	3.57%	5.00%	4.41%	4.90%	4.77%	7.97%	8.34%	8.57%	7.97%	8.34%	8.57%
PNM Resources, Inc.	PNM	$1.16	$49.70	2.33%	2.41%	7.00%	6.35%	5.60%	6.32%	8.00%	8.72%	9.42%	8.00%	8.72%	9.42%
Portland General Electric Company	POR	$1.54	$55.96	2.75%	2.81%	4.50%	4.10%	4.50%	4.37%	6.91%	7.18%	7.31%		7.18%	7.31%
PPL Corporation	PPL	$1.65	$33.47	4.93%	4.95%	1.50%	0.50%	NA%	1.00%	5.44%	5.95%	6.47%			
Southern Company	SO	$2.48	$61.84	4.01%	4.07%	3.50%	1.56%	4.50%	3.19%	5.60%	7.26%	8.60%		7.26%	8.60%
Xcel Energy Inc.	XEL	$1.62	$62.00	2.61%	2.68%	5.50%	5.20%	5.40%	5.37%	7.88%	8.05%	8.18%	7.88%	8.05%	8.18%
MEAN				3.19%	3.27%	5.50%	4.82%	5.43%	5.21%	7.54%	8.48%	9.51%	8.34%	9.04%	10.10%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of November 29, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line Investment Survey
[6] Source: Yahoo! Finance
[7] Source: Zacks
[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])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

90-DAY CONSTANT GROWTH DCF -- PACIFICORP PROXY GROUP

Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth	All Proxy Group Low ROE	All Proxy Group Mean ROE	All Proxy Group High ROE	With Exclusions Low ROE	With Exclusions Mean ROE	With Exclusions High ROE
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
ALLETE, Inc.	ALE	$2.35	$85.04	2.76%	2.86%	6.00%	7.00%	7.20%	6.73%	8.85%	9.59%	10.06%	8.85%	9.59%	10.06%
Alliant Energy Corporation	LNT	$1.42	$52.35	2.71%	2.79%	6.50%	5.00%	5.50%	5.67%	7.78%	8.46%	9.30%	7.78%	8.46%	9.30%
Ameren Corporation	AEE	$1.90	$76.61	2.48%	2.55%	6.50%	4.70%	6.20%	5.80%	7.24%	8.35%	9.06%	7.24%	8.35%	9.06%
American Electric Power Company, Inc.	AEP	$2.80	$91.56	3.06%	3.14%	4.00%	5.90%	5.60%	5.17%	7.12%	8.30%	9.05%	7.12%	8.30%	9.05%
Avista Corporation	AVA	$1.55	$47.21	3.28%	3.34%	3.50%	3.50%	3.40%	3.47%	6.74%	6.81%	6.84%			
CenterPoint Energy, Inc.	CNP	$1.15	$28.32	4.06%	4.20%	12.50%	3.63%	4.80%	6.98%	7.76%	11.18%	16.81%	7.76%	11.18%	16.81%
CMS Energy Corporation	CMS	$1.53	$62.00	2.47%	2.55%	7.00%	7.50%	6.40%	6.97%	8.95%	9.52%	10.06%	8.95%	9.52%	10.06%
Dominion Resources, Inc.	D	$3.67	$79.49	4.62%	4.74%	6.50%	4.41%	4.80%	5.24%	9.13%	9.97%	11.27%	9.13%	9.97%	11.27%
DTE Energy Company	DTE	$3.78	$128.28	2.95%	3.03%	5.50%	4.83%	6.00%	5.44%	7.85%	8.47%	9.04%	7.85%	8.47%	9.04%
Duke Energy Corporation	DUK	$3.78	$92.14	4.10%	4.21%	6.00%	4.65%	4.80%	5.15%	8.85%	9.36%	10.23%	8.85%	9.36%	10.23%
Entergy Corporation	ETR	$3.72	$114.13	3.26%	3.32%	0.50%	Negative	7.00%	3.75%	3.77%	7.07%	10.37%		7.07%	10.37%
Evergy, Inc.	EVRG	$2.02	$64.00	3.16%	3.26%	NMF	6.70%	6.40%	6.55%	9.66%	9.81%	9.96%	9.66%	9.81%	9.96%
FirstEnergy Corporation	FE	$1.52	$46.68	3.26%	3.36%	6.50%	Negative	6.00%	6.25%	9.35%	9.61%	9.86%	9.35%	9.61%	9.86%
IDACORP, Inc.	IDA	$2.68	$107.53	2.49%	2.53%	3.50%	2.50%	3.80%	3.27%	5.02%	5.80%	6.34%			
NextEra Energy, Inc.	NEE	$5.00	$225.09	2.22%	2.32%	10.50%	7.99%	8.00%	8.83%	10.30%	11.15%	12.84%	10.30%	11.15%	12.84%
NorthWestern Corporation	NWE	$2.30	$72.17	3.19%	3.23%	3.00%	3.20%	2.70%	2.97%	5.93%	6.20%	6.44%			
OGE Energy Corporation	OGE	$1.55	$43.25	3.58%	3.67%	6.50%	3.50%	4.50%	4.83%	7.15%	8.50%	10.20%	7.15%	8.50%	10.20%
Otter Tail Corporation	OTTR	$1.40	$52.39	2.67%	2.77%	5.00%	9.00%	7.00%	7.00%	7.74%	9.77%	11.79%	7.74%	9.77%	11.79%
Pinnacle West Capital Corporation	PNW	$3.13	$92.92	3.37%	3.45%	5.00%	4.41%	4.90%	4.77%	7.85%	8.22%	8.45%	7.85%	8.22%	8.45%
PNM Resources, Inc.	PNM	$1.16	$50.46	2.30%	2.37%	7.00%	6.35%	5.60%	6.32%	7.96%	8.69%	9.38%	7.96%	8.69%	9.38%
Portland General Electric Company	POR	$1.54	$55.99	2.75%	2.81%	4.50%	4.10%	4.50%	4.37%	6.91%	7.18%	7.31%		7.18%	7.31%
PPL Corporation	PPL	$1.65	$31.38	5.26%	5.28%	1.50%	0.50%	NA%	1.00%	5.77%	6.28%	6.80%			
Southern Company	SO	$2.48	$60.14	4.12%	4.19%	3.50%	1.56%	4.50%	3.19%	5.72%	7.38%	8.72%		7.38%	8.72%
Xcel Energy Inc.	XEL	$1.62	$62.70	2.58%	2.65%	5.50%	5.20%	5.40%	5.37%	7.85%	8.02%	8.15%	7.85%	8.02%	8.15%
MEAN				3.20%	3.28%	5.50%	4.82%	5.43%	5.21%	7.55%	8.49%	9.51%	8.32%	8.93%	10.10%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of November 29, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line Investment Survey
[6] Source: Yahoo! Finance
[7] Source: Zacks
[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])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

180-DAY CONSTANT GROWTH DCF -- PACIFICORP PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] All Proxy Group	[10] All Proxy Group	[11] All Proxy Group	[12] With Exclusions	[13] With Exclusions	[14] With Exclusions
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.35	$84.03	2.80%	2.89%	6.00%	7.00%	7.20%	6.73%	8.88%	9.62%	10.10%	8.88%	9.62%	10.10%
Alliant Energy Corporation	LNT	$1.42	$50.20	2.83%	2.91%	6.50%	5.00%	5.50%	5.67%	7.90%	8.58%	9.42%	7.90%	8.58%	9.42%
Ameren Corporation	AEE	$1.90	$75.41	2.52%	2.59%	6.50%	4.70%	6.20%	5.80%	7.28%	8.39%	9.10%	7.28%	8.39%	9.10%
American Electric Power Company, Inc.	AEP	$2.80	$89.15	3.14%	3.22%	4.00%	5.90%	5.60%	5.17%	7.20%	8.39%	9.13%	7.20%	8.39%	9.13%
Avista Corporation	AVA	$1.55	$45.05	3.44%	3.50%	3.50%	3.50%	3.40%	3.47%	6.90%	6.97%	7.00%			7.00%
CenterPoint Energy, Inc.	CNP	$1.15	$29.03	3.96%	4.10%	12.50%	3.63%	4.80%	6.98%	7.66%	11.08%	16.71%	7.66%	11.08%	16.71%
CMS Energy Corporation	CMS	$1.53	$59.25	2.58%	2.67%	7.00%	7.50%	6.40%	6.97%	9.06%	9.64%	10.18%	9.06%	9.64%	10.18%
Dominion Resources, Inc.	D	$3.67	$77.94	4.71%	4.83%	6.50%	4.41%	4.80%	5.24%	9.22%	10.07%	11.36%	9.22%	10.07%	11.36%
DTE Energy Company	DTE	$3.78	$127.46	2.97%	3.05%	5.50%	4.83%	6.00%	5.44%	7.87%	8.49%	9.05%	7.87%	8.49%	9.05%
Duke Energy Corporation	DUK	$3.78	$90.42	4.18%	4.29%	6.00%	4.65%	4.80%	5.15%	8.93%	9.44%	10.31%	8.93%	9.44%	10.31%
Entergy Corporation	ETR	$3.72	$106.35	3.50%	3.56%	0.50%	Negative	7.00%	3.75%	4.01%	7.31%	10.62%		7.31%	10.62%
Evergy, Inc.	EVRG	$2.02	$61.44	3.29%	3.40%	NMF	6.70%	6.40%	6.55%	9.79%	9.95%	10.10%	9.79%	9.95%	10.10%
FirstEnergy Corporation	FE	$1.52	$44.46	3.42%	3.53%	6.50%	Negative	6.00%	6.25%	9.52%	9.78%	10.03%	9.52%	9.78%	10.03%
IDACORP, Inc.	IDA	$2.68	$104.38	2.57%	2.61%	3.50%	2.50%	3.80%	3.27%	5.10%	5.88%	6.42%			
NextEra Energy, Inc.	NEE	$5.00	$211.83	2.36%	2.46%	10.50%	7.99%	8.00%	8.83%	10.44%	11.29%	12.98%	10.44%	11.29%	12.98%
NorthWestern Corporation	NWE	$2.30	$71.71	3.21%	3.25%	3.00%	3.20%	2.70%	2.97%	5.95%	6.22%	6.46%			
OGE Energy Corporation	OGE	$1.55	$42.90	3.61%	3.70%	6.50%	3.50%	4.50%	4.83%	7.18%	8.53%	10.23%	7.18%	8.53%	10.23%
Otter Tail Corporation	OTTR	$1.40	$51.72	2.71%	2.80%	5.00%	9.00%	7.00%	7.00%	7.77%	9.80%	11.83%	7.77%	9.80%	11.83%
Pinnacle West Capital Corporation	PNW	$3.13	$94.04	3.33%	3.41%	5.00%	4.41%	4.90%	4.77%	7.81%	8.18%	8.41%	7.81%	8.18%	8.41%
PNM Resources, Inc.	PNM	$1.16	$49.29	2.35%	2.43%	7.00%	6.35%	5.60%	6.32%	8.02%	8.74%	9.44%	8.02%	8.74%	9.44%
Portland General Electric Company	POR	$1.54	$54.58	2.82%	2.88%	4.50%	4.10%	4.50%	4.37%	6.98%	7.25%	7.39%		7.25%	7.39%
PPL Corporation	PPL	$1.65	$31.21	5.29%	5.31%	1.50%	0.50%	NA%	1.00%	5.80%	6.31%	6.83%			
Southern Company	SO	$2.48	$56.97	4.35%	4.42%	3.50%	1.56%	4.50%	3.19%	5.95%	7.61%	8.95%		7.61%	8.95%
Xcel Energy Inc.	XEL	$1.62	$60.35	2.68%	2.76%	5.50%	5.20%	5.40%	5.37%	7.95%	8.12%	8.26%	7.95%	8.12%	8.26%
MEAN				3.28%	3.36%	5.50%	4.82%	5.43%	5.21%	7.63%	8.57%	9.60%	8.38%	9.01%	10.03%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of November 29, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line Investment Survey
[6] Source: Yahoo! Finance
[7] Source: Zacks
[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])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

Docket No. UE 374
Exhibit PAC/405
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Multi-Stage Discounted Cash Flow Model

February 2020

30-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$82.86	$2.35	6.73%	6.53%	6.33%	6.13%	5.93%	5.73%	5.53%	8.89%
Alliant Energy Corporation	LNT	$52.75	$1.42	5.67%	5.64%	5.62%	5.60%	5.57%	5.55%	5.53%	8.49%
Ameren Corporation	AEE	$75.74	$1.90	5.80%	5.75%	5.71%	5.66%	5.62%	5.57%	5.53%	8.31%
American Electric Power Company, Inc.	AEP	$91.90	$2.80	5.17%	5.23%	5.29%	5.35%	5.41%	5.47%	5.53%	8.79%
Avista Corporation	AVA	$47.34	$1.55	3.47%	3.81%	4.15%	4.50%	4.84%	5.18%	5.53%	8.66%
CenterPoint Energy, Inc.	CNP	$27.47	$1.15	6.98%	6.73%	6.49%	6.25%	6.01%	5.77%	5.53%	10.59%
CMS Energy Corporation	CMS	$61.94	$1.53	6.97%	6.73%	6.49%	6.25%	6.01%	5.77%	5.53%	8.49%
Dominion Resources, Inc.	D	$82.08	$3.67	5.24%	5.28%	5.33%	5.38%	5.43%	5.48%	5.53%	10.39%
DTE Energy Company	DTE	$124.95	$3.78	5.44%	5.46%	5.47%	5.48%	5.50%	5.51%	5.53%	8.82%
Duke Energy Corporation	DUK	$91.21	$3.78	5.15%	5.21%	5.28%	5.34%	5.40%	5.46%	5.53%	10.00%
Entergy Corporation	ETR	$117.56	$3.72	3.75%	4.05%	4.34%	4.64%	4.93%	5.23%	5.53%	8.61%
Evergy, Inc.	EVRG	$63.69	$2.02	6.55%	6.38%	6.21%	6.04%	5.87%	5.70%	5.53%	9.25%
FirstEnergy Corporation	FE	$47.44	$1.52	6.25%	6.13%	6.01%	5.89%	5.77%	5.65%	5.53%	9.21%
IDACORP, Inc.	IDA	$105.93	$2.68	3.27%	3.64%	4.02%	4.40%	4.77%	5.15%	5.53%	7.88%
NextEra Energy, Inc.	NEE	$231.81	$5.00	8.83%	8.28%	7.73%	7.18%	6.63%	6.08%	5.53%	8.44%
NorthWestern Corporation	NWE	$71.47	$2.30	2.97%	3.39%	3.82%	4.25%	4.67%	5.10%	5.53%	8.50%
OGE Energy Corporation	OGE	$42.84	$1.55	4.83%	4.95%	5.06%	5.18%	5.30%	5.41%	5.53%	9.34%
Otter Tail Corporation	OTTR	$51.99	$1.40	7.00%	6.75%	6.51%	6.26%	6.02%	5.77%	5.53%	8.77%
Pinnacle West Capital Corporation	PNW	$89.87	$3.13	4.77%	4.90%	5.02%	5.15%	5.27%	5.40%	5.53%	9.18%
PNM Resources, Inc.	PNM	$49.70	$1.16	6.32%	6.18%	6.05%	5.92%	5.79%	5.66%	5.53%	8.20%
Portland General Electric Company	POR	$55.96	$1.54	4.37%	4.56%	4.75%	4.95%	5.14%	5.33%	5.53%	8.31%
PPL Corporation	PPL	$33.47	$1.65	1.00%	1.75%	2.51%	3.26%	4.02%	4.77%	5.53%	9.61%
Southern Company	SO	$61.84	$2.48	3.19%	3.58%	3.97%	4.36%	4.75%	5.14%	5.53%	9.33%
Xcel Energy Inc.	XEL	$62.00	$1.62	5.37%	5.39%	5.42%	5.45%	5.47%	5.50%	5.53%	8.35%
MEAN											**8.93%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of November 29, 2019
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC 204
[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 206
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$85.04	$2.35	6.73%	6.53%	6.33%	6.13%	5.93%	5.73%	5.53%	8.80%
Alliant Energy Corporation	LNT	$52.35	$1.42	5.67%	5.64%	5.62%	5.60%	5.57%	5.55%	5.53%	8.52%
Ameren Corporation	AEE	$76.61	$1.90	5.80%	5.75%	5.71%	5.66%	5.62%	5.57%	5.53%	8.28%
American Electric Power Company, Inc.	AEP	$91.56	$2.80	5.17%	5.23%	5.29%	5.35%	5.41%	5.47%	5.53%	8.80%
Avista Corporation	AVA	$47.21	$1.55	3.47%	3.81%	4.15%	4.50%	4.84%	5.18%	5.53%	8.67%
CenterPoint Energy, Inc.	CNP	$28.32	$1.15	6.98%	6.73%	6.49%	6.25%	6.01%	5.77%	5.53%	10.44%
CMS Energy Corporation	CMS	$62.00	$1.53	6.97%	6.73%	6.49%	6.25%	6.01%	5.77%	5.53%	8.48%
Dominion Resources, Inc.	D	$79.49	$3.67	5.24%	5.28%	5.33%	5.38%	5.43%	5.48%	5.53%	10.55%
DTE Energy Company	DTE	$128.28	$3.78	5.44%	5.46%	5.47%	5.48%	5.50%	5.51%	5.53%	8.74%
Duke Energy Corporation	DUK	$92.14	$3.78	5.15%	5.21%	5.28%	5.34%	5.40%	5.46%	5.53%	9.95%
Entergy Corporation	ETR	$114.13	$3.72	3.75%	4.05%	4.34%	4.64%	4.93%	5.23%	5.53%	8.71%
Evergy, Inc.	EVRG	$64.00	$2.02	6.55%	6.38%	6.21%	6.04%	5.87%	5.70%	5.53%	9.23%
FirstEnergy Corporation	FE	$46.68	$1.52	6.25%	6.13%	6.01%	5.89%	5.77%	5.65%	5.53%	9.28%
IDACORP, Inc.	IDA	$107.53	$2.68	3.27%	3.64%	4.02%	4.40%	4.77%	5.15%	5.53%	7.84%
NextEra Energy, Inc.	NEE	$225.09	$5.00	8.83%	8.28%	7.73%	7.18%	6.63%	6.08%	5.53%	8.53%
NorthWestern Corporation	NWE	$72.17	$2.30	2.97%	3.39%	3.82%	4.25%	4.67%	5.10%	5.53%	8.47%
OGE Energy Corporation	OGE	$43.25	$1.55	4.83%	4.95%	5.06%	5.18%	5.30%	5.41%	5.53%	9.30%
Otter Tail Corporation	OTTR	$52.39	$1.40	7.00%	6.75%	6.51%	6.26%	6.02%	5.77%	5.53%	8.74%
Pinnacle West Capital Corporation	PNW	$92.92	$3.13	4.77%	4.90%	5.02%	5.15%	5.27%	5.40%	5.53%	9.05%
PNM Resources, Inc.	PNM	$50.46	$1.16	6.32%	6.18%	6.05%	5.92%	5.79%	5.66%	5.53%	8.16%
Portland General Electric Company	POR	$55.99	$1.54	4.37%	4.56%	4.75%	4.95%	5.14%	5.33%	5.53%	8.31%
PPL Corporation	PPL	$31.38	$1.65	1.00%	1.75%	2.51%	3.26%	4.02%	4.77%	5.53%	9.90%
Southern Company	SO	$60.14	$2.48	3.19%	3.58%	3.97%	4.36%	4.75%	5.14%	5.53%	9.44%
Xcel Energy Inc.	XEL	$62.70	$1.62	5.37%	5.39%	5.42%	5.45%	5.47%	5.50%	5.53%	8.31%
MEAN											**8.94%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of November 29, 2019
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC 204
[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 206
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$84.03	$2.35	6.73%	6.53%	6.33%	6.13%	5.93%	5.73%	5.53%	8.84%
Alliant Energy Corporation	LNT	$50.20	$1.42	5.67%	5.64%	5.62%	5.60%	5.57%	5.55%	5.53%	8.65%
Ameren Corporation	AEE	$75.41	$1.90	5.80%	5.75%	5.71%	5.66%	5.62%	5.57%	5.53%	8.32%
American Electric Power Company, Inc.	AEP	$89.15	$2.80	5.17%	5.23%	5.29%	5.35%	5.41%	5.47%	5.53%	8.89%
Avista Corporation	AVA	$45.05	$1.55	3.47%	3.81%	4.15%	4.50%	4.84%	5.18%	5.53%	8.83%
CenterPoint Energy, Inc.	CNP	$29.03	$1.15	6.98%	6.73%	6.49%	6.25%	6.01%	5.77%	5.53%	10.32%
CMS Energy Corporation	CMS	$59.25	$1.53	6.97%	6.73%	6.49%	6.25%	6.01%	5.77%	5.53%	8.63%
Dominion Resources, Inc.	D	$77.94	$3.67	5.24%	5.28%	5.33%	5.38%	5.43%	5.48%	5.53%	10.65%
DTE Energy Company	DTE	$127.46	$3.78	5.44%	5.46%	5.47%	5.48%	5.50%	5.51%	5.53%	8.76%
Duke Energy Corporation	DUK	$90.42	$3.78	5.15%	5.21%	5.28%	5.34%	5.40%	5.46%	5.53%	10.04%
Entergy Corporation	ETR	$106.35	$3.72	3.75%	4.05%	4.34%	4.64%	4.93%	5.23%	5.53%	8.95%
Evergy, Inc.	EVRG	$61.44	$2.02	6.55%	6.38%	6.21%	6.04%	5.87%	5.70%	5.53%	9.39%
FirstEnergy Corporation	FE	$44.46	$1.52	6.25%	6.13%	6.01%	5.89%	5.77%	5.65%	5.53%	9.47%
IDACORP, Inc.	IDA	$104.38	$2.68	3.27%	3.64%	4.02%	4.40%	4.77%	5.15%	5.53%	7.92%
NextEra Energy, Inc.	NEE	$211.83	$5.00	8.83%	8.28%	7.73%	7.18%	6.63%	6.08%	5.53%	8.72%
NorthWestern Corporation	NWE	$71.71	$2.30	2.97%	3.39%	3.82%	4.25%	4.67%	5.10%	5.53%	8.49%
OGE Energy Corporation	OGE	$42.90	$1.55	4.83%	4.95%	5.06%	5.18%	5.30%	5.41%	5.53%	9.33%
Otter Tail Corporation	OTTR	$51.72	$1.40	7.00%	6.75%	6.51%	6.26%	6.02%	5.77%	5.53%	8.79%
Pinnacle West Capital Corporation	PNW	$94.04	$3.13	4.77%	4.90%	5.02%	5.15%	5.27%	5.40%	5.53%	9.01%
PNM Resources, Inc.	PNM	$49.29	$1.16	6.32%	6.18%	6.05%	5.92%	5.79%	5.66%	5.53%	8.22%
Portland General Electric Company	POR	$54.58	$1.54	4.37%	4.56%	4.75%	4.95%	5.14%	5.33%	5.53%	8.38%
PPL Corporation	PPL	$31.21	$1.65	1.00%	1.75%	2.51%	3.26%	4.02%	4.77%	5.53%	9.92%
Southern Company	SO	$56.97	$2.48	3.19%	3.58%	3.97%	4.36%	4.75%	5.14%	5.53%	9.67%
Xcel Energy Inc.	XEL	$60.35	$1.62	5.37%	5.39%	5.42%	5.45%	5.47%	5.50%	5.53%	8.43%
MEAN											**9.03%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of November 29, 2019
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC 204
[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 206
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$82.86	$2.35	6.00%	5.92%	5.84%	5.76%	5.68%	5.61%	5.53%	8.73%
Alliant Energy Corporation	LNT	$52.75	$1.42	5.00%	5.09%	5.18%	5.26%	5.35%	5.44%	5.53%	8.36%
Ameren Corporation	AEE	$75.74	$1.90	4.70%	4.84%	4.98%	5.11%	5.25%	5.39%	5.53%	8.11%
American Electric Power Company, Inc.	AEP	$91.90	$2.80	4.00%	4.25%	4.51%	4.76%	5.02%	5.27%	5.53%	8.54%
Avista Corporation	AVA	$47.34	$1.55	3.40%	3.75%	4.11%	4.46%	4.82%	5.17%	5.53%	8.65%
CenterPoint Energy, Inc.	CNP	$27.47	$1.15	3.63%	3.95%	4.26%	4.58%	4.89%	5.21%	5.53%	9.62%
CMS Energy Corporation	CMS	$61.94	$1.53	6.40%	6.25%	6.11%	5.96%	5.82%	5.67%	5.53%	8.38%
Dominion Resources, Inc.	D	$82.08	$3.67	4.41%	4.60%	4.78%	4.97%	5.15%	5.34%	5.53%	10.14%
DTE Energy Company	DTE	$124.95	$3.78	4.83%	4.95%	5.06%	5.18%	5.29%	5.41%	5.53%	8.69%
Duke Energy Corporation	DUK	$91.21	$3.78	4.65%	4.80%	4.94%	5.09%	5.23%	5.38%	5.53%	9.86%
Entergy Corporation	ETR	$117.56	$3.72	0.50%	1.34%	2.18%	3.01%	3.85%	4.69%	5.53%	7.98%
Evergy, Inc.	EVRG	$63.69	$2.02	6.40%	6.25%	6.11%	5.96%	5.82%	5.67%	5.53%	9.21%
FirstEnergy Corporation	FE	$47.44	$1.52	6.00%	5.92%	5.84%	5.76%	5.68%	5.61%	5.53%	9.16%
IDACORP, Inc.	IDA	$105.93	$2.68	2.50%	3.00%	3.51%	4.01%	4.52%	5.02%	5.53%	7.75%
NextEra Energy, Inc.	NEE	$231.81	$5.00	7.99%	7.58%	7.17%	6.76%	6.35%	5.94%	5.53%	8.28%
NorthWestern Corporation	NWE	$71.47	$2.30	2.70%	3.17%	3.64%	4.11%	4.58%	5.06%	5.53%	8.45%
OGE Energy Corporation	OGE	$42.84	$1.55	3.50%	3.84%	4.18%	4.51%	4.85%	5.19%	5.53%	9.02%
Otter Tail Corporation	OTTR	$51.99	$1.40	5.00%	5.09%	5.18%	5.26%	5.35%	5.44%	5.53%	8.36%
Pinnacle West Capital Corporation	PNW	$89.87	$3.13	4.41%	4.60%	4.78%	4.97%	5.15%	5.34%	5.53%	9.09%
PNM Resources, Inc.	PNM	$49.70	$1.16	5.60%	5.59%	5.58%	5.56%	5.55%	5.54%	5.53%	8.07%
Portland General Electric Company	POR	$55.96	$1.54	4.10%	4.34%	4.58%	4.81%	5.05%	5.29%	5.53%	8.26%
PPL Corporation	PPL	$33.47	$1.65	0.50%	1.34%	2.18%	3.01%	3.85%	4.69%	5.53%	9.47%
Southern Company	SO	$61.84	$2.48	1.56%	2.22%	2.88%	3.54%	4.20%	4.87%	5.53%	8.93%
Xcel Energy Inc.	XEL	$62.00	$1.62	5.20%	5.25%	5.31%	5.36%	5.42%	5.47%	5.53%	8.31%
MEAN											**8.73%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of November 29, 2019
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC 204
[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 206
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$85.04	$2.35	6.00%	5.92%	5.84%	5.76%	5.68%	5.61%	5.53%	8.64%
Alliant Energy Corporation	LNT	$52.35	$1.42	5.00%	5.09%	5.18%	5.26%	5.35%	5.44%	5.53%	8.39%
Ameren Corporation	AEE	$76.61	$1.90	4.70%	4.84%	4.98%	5.11%	5.25%	5.39%	5.53%	8.08%
American Electric Power Company, Inc.	AEP	$91.56	$2.80	4.00%	4.25%	4.51%	4.76%	5.02%	5.27%	5.53%	8.55%
Avista Corporation	AVA	$47.21	$1.55	3.40%	3.75%	4.11%	4.46%	4.82%	5.17%	5.53%	8.66%
CenterPoint Energy, Inc.	CNP	$28.32	$1.15	3.63%	3.95%	4.26%	4.58%	4.89%	5.21%	5.53%	9.50%
CMS Energy Corporation	CMS	$62.00	$1.53	6.40%	6.25%	6.11%	5.96%	5.82%	5.67%	5.53%	8.37%
Dominion Resources, Inc.	D	$79.49	$3.67	4.41%	4.60%	4.78%	4.97%	5.15%	5.34%	5.53%	10.29%
DTE Energy Company	DTE	$128.28	$3.78	4.83%	4.95%	5.06%	5.18%	5.29%	5.41%	5.53%	8.61%
Duke Energy Corporation	DUK	$92.14	$3.78	4.65%	4.80%	4.94%	5.09%	5.23%	5.38%	5.53%	9.81%
Entergy Corporation	ETR	$114.13	$3.72	0.50%	1.34%	2.18%	3.01%	3.85%	4.69%	5.53%	8.06%
Evergy, Inc.	EVRG	$64.00	$2.02	6.40%	6.25%	6.11%	5.96%	5.82%	5.67%	5.53%	9.19%
FirstEnergy Corporation	FE	$46.68	$1.52	6.00%	5.92%	5.84%	5.76%	5.68%	5.61%	5.53%	9.22%
IDACORP, Inc.	IDA	$107.53	$2.68	2.50%	3.00%	3.51%	4.01%	4.52%	5.02%	5.53%	7.71%
NextEra Energy, Inc.	NEE	$225.09	$5.00	7.99%	7.58%	7.17%	6.76%	6.35%	5.94%	5.53%	8.37%
NorthWestern Corporation	NWE	$72.17	$2.30	2.70%	3.17%	3.64%	4.11%	4.58%	5.06%	5.53%	8.42%
OGE Energy Corporation	OGE	$43.25	$1.55	3.50%	3.84%	4.18%	4.51%	4.85%	5.19%	5.53%	8.98%
Otter Tail Corporation	OTTR	$52.39	$1.40	5.00%	5.09%	5.18%	5.26%	5.35%	5.44%	5.53%	8.34%
Pinnacle West Capital Corporation	PNW	$92.92	$3.13	4.41%	4.60%	4.78%	4.97%	5.15%	5.34%	5.53%	8.97%
PNM Resources, Inc.	PNM	$50.46	$1.16	5.60%	5.59%	5.58%	5.56%	5.55%	5.54%	5.53%	8.03%
Portland General Electric Company	POR	$55.99	$1.54	4.10%	4.34%	4.58%	4.81%	5.05%	5.29%	5.53%	8.25%
PPL Corporation	PPL	$31.38	$1.65	0.50%	1.34%	2.18%	3.01%	3.85%	4.69%	5.53%	9.75%
Southern Company	SO	$60.14	$2.48	1.56%	2.22%	2.88%	3.54%	4.20%	4.87%	5.53%	9.04%
Xcel Energy Inc.	XEL	$62.70	$1.62	5.20%	5.25%	5.31%	5.36%	5.42%	5.47%	5.53%	8.28%
MEAN											**8.73%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of November 29, 2019
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC 204
[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 206
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$84.03	$2.35	6.00%	5.92%	5.84%	5.76%	5.68%	5.61%	5.53%	8.68%
Alliant Energy Corporation	LNT	$50.20	$1.42	5.00%	5.09%	5.18%	5.26%	5.35%	5.44%	5.53%	8.51%
Ameren Corporation	AEE	$75.41	$1.90	4.70%	4.84%	4.98%	5.11%	5.25%	5.39%	5.53%	8.12%
American Electric Power Company, Inc.	AEP	$89.15	$2.80	4.00%	4.25%	4.51%	4.76%	5.02%	5.27%	5.53%	8.64%
Avista Corporation	AVA	$45.05	$1.55	3.40%	3.75%	4.11%	4.46%	4.82%	5.17%	5.53%	8.82%
CenterPoint Energy, Inc.	CNP	$29.03	$1.15	3.63%	3.95%	4.26%	4.58%	4.89%	5.21%	5.53%	9.39%
CMS Energy Corporation	CMS	$59.25	$1.53	6.40%	6.25%	6.11%	5.96%	5.82%	5.67%	5.53%	8.51%
Dominion Resources, Inc.	D	$77.94	$3.67	4.41%	4.60%	4.78%	4.97%	5.15%	5.34%	5.53%	10.39%
DTE Energy Company	DTE	$127.46	$3.78	4.83%	4.95%	5.06%	5.18%	5.29%	5.41%	5.53%	8.63%
Duke Energy Corporation	DUK	$90.42	$3.78	4.65%	4.80%	4.94%	5.09%	5.23%	5.38%	5.53%	9.90%
Entergy Corporation	ETR	$106.35	$3.72	0.50%	1.34%	2.18%	3.01%	3.85%	4.69%	5.53%	8.26%
Evergy, Inc.	EVRG	$61.44	$2.02	6.40%	6.25%	6.11%	5.96%	5.82%	5.67%	5.53%	9.35%
FirstEnergy Corporation	FE	$44.46	$1.52	6.00%	5.92%	5.84%	5.76%	5.68%	5.61%	5.53%	9.40%
IDACORP, Inc.	IDA	$104.38	$2.68	2.50%	3.00%	3.51%	4.01%	4.52%	5.02%	5.53%	7.79%
NextEra Energy, Inc.	NEE	$211.83	$5.00	7.99%	7.58%	7.17%	6.76%	6.35%	5.94%	5.53%	8.55%
NorthWestern Corporation	NWE	$71.71	$2.30	2.70%	3.17%	3.64%	4.11%	4.58%	5.06%	5.53%	8.44%
OGE Energy Corporation	OGE	$42.90	$1.55	3.50%	3.84%	4.18%	4.51%	4.85%	5.19%	5.53%	9.01%
Otter Tail Corporation	OTTR	$51.72	$1.40	5.00%	5.09%	5.18%	5.26%	5.35%	5.44%	5.53%	8.38%
Pinnacle West Capital Corporation	PNW	$94.04	$3.13	4.41%	4.60%	4.78%	4.97%	5.15%	5.34%	5.53%	8.93%
PNM Resources, Inc.	PNM	$49.29	$1.16	5.60%	5.59%	5.58%	5.56%	5.55%	5.54%	5.53%	8.09%
Portland General Electric Company	POR	$54.58	$1.54	4.10%	4.34%	4.58%	4.81%	5.05%	5.29%	5.53%	8.33%
PPL Corporation	PPL	$31.21	$1.65	0.50%	1.34%	2.18%	3.01%	3.85%	4.69%	5.53%	9.78%
Southern Company	SO	$56.97	$2.48	1.56%	2.22%	2.88%	3.54%	4.20%	4.87%	5.53%	9.24%
Xcel Energy Inc.	XEL	$60.35	$1.62	5.20%	5.25%	5.31%	5.36%	5.42%	5.47%	5.53%	8.39%
MEAN											**8.81%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of November 29, 2019
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC 204
[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 206
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$82.86	$2.35	7.20%	6.92%	6.64%	6.36%	6.08%	5.81%	5.53%	8.99%
Alliant Energy Corporation	LNT	$52.75	$1.42	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	8.66%
Ameren Corporation	AEE	$75.74	$1.90	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	8.44%
American Electric Power Company, Inc.	AEP	$91.90	$2.80	5.90%	5.84%	5.78%	5.71%	5.65%	5.59%	5.53%	8.95%
Avista Corporation	AVA	$47.34	$1.55	3.50%	3.84%	4.18%	4.51%	4.85%	5.19%	5.53%	8.67%
CenterPoint Energy, Inc.	CNP	$27.47	$1.15	12.50%	11.34%	10.18%	9.01%	7.85%	6.69%	5.53%	12.50%
CMS Energy Corporation	CMS	$61.94	$1.53	7.50%	7.17%	6.84%	6.51%	6.18%	5.86%	5.53%	8.59%
Dominion Resources, Inc.	D	$82.08	$3.67	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	10.78%
DTE Energy Company	DTE	$124.95	$3.78	6.00%	5.92%	5.84%	5.76%	5.68%	5.61%	5.53%	8.95%
Duke Energy Corporation	DUK	$91.21	$3.78	6.00%	5.92%	5.84%	5.76%	5.68%	5.61%	5.53%	10.24%
Entergy Corporation	ETR	$117.56	$3.72	7.00%	6.75%	6.51%	6.26%	6.02%	5.77%	5.53%	9.35%
Evergy, Inc.	EVRG	$63.69	$2.02	6.70%	6.50%	6.31%	6.11%	5.92%	5.72%	5.53%	9.28%
FirstEnergy Corporation	FE	$47.44	$1.52	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	9.27%
IDACORP, Inc.	IDA	$105.93	$2.68	3.80%	4.09%	4.38%	4.66%	4.95%	5.24%	5.53%	7.97%
NextEra Energy, Inc.	NEE	$231.81	$5.00	10.50%	9.67%	8.84%	8.01%	7.18%	6.36%	5.53%	8.77%
NorthWestern Corporation	NWE	$71.47	$2.30	3.20%	3.59%	3.98%	4.36%	4.75%	5.14%	5.53%	8.55%
OGE Energy Corporation	OGE	$42.84	$1.55	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	9.77%
Otter Tail Corporation	OTTR	$51.99	$1.40	9.00%	8.42%	7.84%	7.26%	6.68%	6.11%	5.53%	9.21%
Pinnacle West Capital Corporation	PNW	$89.87	$3.13	5.00%	5.09%	5.18%	5.26%	5.35%	5.44%	5.53%	9.23%
PNM Resources, Inc.	PNM	$49.70	$1.16	7.00%	6.75%	6.51%	6.26%	6.02%	5.77%	5.53%	8.33%
Portland General Electric Company	POR	$55.96	$1.54	4.50%	4.67%	4.84%	5.01%	5.18%	5.36%	5.53%	8.33%
PPL Corporation	PPL	$33.47	$1.65	1.50%	2.17%	2.84%	3.51%	4.18%	4.86%	5.53%	9.75%
Southern Company	SO	$61.84	$2.48	4.50%	4.67%	4.84%	5.01%	5.18%	5.36%	5.53%	9.67%
Xcel Energy Inc.	XEL	$62.00	$1.62	5.50%	5.50%	5.51%	5.51%	5.52%	5.52%	5.53%	8.37%
MEAN											**9.19%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of November 29, 2019
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC 204
[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 206
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$85.04	$2.35	7.20%	6.92%	6.64%	6.36%	6.08%	5.81%	5.53%	8.90%
Alliant Energy Corporation	LNT	$52.35	$1.42	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	8.69%
Ameren Corporation	AEE	$76.61	$1.90	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	8.41%
American Electric Power Company, Inc.	AEP	$91.56	$2.80	5.90%	5.84%	5.78%	5.71%	5.65%	5.59%	5.53%	8.96%
Avista Corporation	AVA	$47.21	$1.55	3.50%	3.84%	4.18%	4.51%	4.85%	5.19%	5.53%	8.68%
CenterPoint Energy, Inc.	CNP	$28.32	$1.15	12.50%	11.34%	10.18%	9.01%	7.85%	6.69%	5.53%	12.30%
CMS Energy Corporation	CMS	$62.00	$1.53	7.50%	7.17%	6.84%	6.51%	6.18%	5.86%	5.53%	8.59%
Dominion Resources, Inc.	D	$79.49	$3.67	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	10.96%
DTE Energy Company	DTE	$128.28	$3.78	6.00%	5.92%	5.84%	5.76%	5.68%	5.61%	5.53%	8.86%
Duke Energy Corporation	DUK	$92.14	$3.78	6.00%	5.92%	5.84%	5.76%	5.68%	5.61%	5.53%	10.20%
Entergy Corporation	ETR	$114.13	$3.72	7.00%	6.75%	6.51%	6.26%	6.02%	5.77%	5.53%	9.46%
Evergy, Inc.	EVRG	$64.00	$2.02	6.70%	6.50%	6.31%	6.11%	5.92%	5.72%	5.53%	9.26%
FirstEnergy Corporation	FE	$46.68	$1.52	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	9.34%
IDACORP, Inc.	IDA	$107.53	$2.68	3.80%	4.09%	4.38%	4.66%	4.95%	5.24%	5.53%	7.93%
NextEra Energy, Inc.	NEE	$225.09	$5.00	10.50%	9.67%	8.84%	8.01%	7.18%	6.36%	5.53%	8.86%
NorthWestern Corporation	NWE	$72.17	$2.30	3.20%	3.59%	3.98%	4.36%	4.75%	5.14%	5.53%	8.52%
OGE Energy Corporation	OGE	$43.25	$1.55	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	9.73%
Otter Tail Corporation	OTTR	$52.39	$1.40	9.00%	8.42%	7.84%	7.26%	6.68%	6.11%	5.53%	9.18%
Pinnacle West Capital Corporation	PNW	$92.92	$3.13	5.00%	5.09%	5.18%	5.26%	5.35%	5.44%	5.53%	9.10%
PNM Resources, Inc.	PNM	$50.46	$1.16	7.00%	6.75%	6.51%	6.26%	6.02%	5.77%	5.53%	8.28%
Portland General Electric Company	POR	$55.99	$1.54	4.50%	4.67%	4.84%	5.01%	5.18%	5.36%	5.53%	8.33%
PPL Corporation	PPL	$31.38	$1.65	1.50%	2.17%	2.84%	3.51%	4.18%	4.86%	5.53%	10.05%
Southern Company	SO	$60.14	$2.48	4.50%	4.67%	4.84%	5.01%	5.18%	5.36%	5.53%	9.79%
Xcel Energy Inc.	XEL	$62.70	$1.62	5.50%	5.50%	5.51%	5.51%	5.52%	5.52%	5.53%	8.34%
MEAN											**9.20%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of November 29, 2019
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC 204
[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 206
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$84.03	$2.35	7.20%	6.92%	6.64%	6.36%	6.08%	5.81%	5.53%	8.94%
Alliant Energy Corporation	LNT	$50.20	$1.42	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	8.83%
Ameren Corporation	AEE	$75.41	$1.90	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	8.46%
American Electric Power Company, Inc.	AEP	$89.15	$2.80	5.90%	5.84%	5.78%	5.71%	5.65%	5.59%	5.53%	9.06%
Avista Corporation	AVA	$45.05	$1.55	3.50%	3.84%	4.18%	4.51%	4.85%	5.19%	5.53%	8.84%
CenterPoint Energy, Inc.	CNP	$29.03	$1.15	12.50%	11.34%	10.18%	9.01%	7.85%	6.69%	5.53%	12.14%
CMS Energy Corporation	CMS	$59.25	$1.53	7.50%	7.17%	6.84%	6.51%	6.18%	5.86%	5.53%	8.74%
Dominion Resources, Inc.	D	$77.94	$3.67	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	11.07%
DTE Energy Company	DTE	$127.46	$3.78	6.00%	5.92%	5.84%	5.76%	5.68%	5.61%	5.53%	8.88%
Duke Energy Corporation	DUK	$90.42	$3.78	6.00%	5.92%	5.84%	5.76%	5.68%	5.61%	5.53%	10.29%
Entergy Corporation	ETR	$106.35	$3.72	7.00%	6.75%	6.51%	6.26%	6.02%	5.77%	5.53%	9.75%
Evergy, Inc.	EVRG	$61.44	$2.02	6.70%	6.50%	6.31%	6.11%	5.92%	5.72%	5.53%	9.42%
FirstEnergy Corporation	FE	$44.46	$1.52	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	9.53%
IDACORP, Inc.	IDA	$104.38	$2.68	3.80%	4.09%	4.38%	4.66%	4.95%	5.24%	5.53%	8.01%
NextEra Energy, Inc.	NEE	$211.83	$5.00	10.50%	9.67%	8.84%	8.01%	7.18%	6.36%	5.53%	9.07%
NorthWestern Corporation	NWE	$71.71	$2.30	3.20%	3.59%	3.98%	4.36%	4.75%	5.14%	5.53%	8.54%
OGE Energy Corporation	OGE	$42.90	$1.55	6.50%	6.34%	6.18%	6.01%	5.85%	5.69%	5.53%	9.76%
Otter Tail Corporation	OTTR	$51.72	$1.40	9.00%	8.42%	7.84%	7.26%	6.68%	6.11%	5.53%	9.23%
Pinnacle West Capital Corporation	PNW	$94.04	$3.13	5.00%	5.09%	5.18%	5.26%	5.35%	5.44%	5.53%	9.06%
PNM Resources, Inc.	PNM	$49.29	$1.16	7.00%	6.75%	6.51%	6.26%	6.02%	5.77%	5.53%	8.35%
Portland General Electric Company	POR	$54.58	$1.54	4.50%	4.67%	4.84%	5.01%	5.18%	5.36%	5.53%	8.41%
PPL Corporation	PPL	$31.21	$1.65	1.50%	2.17%	2.84%	3.51%	4.18%	4.86%	5.53%	10.07%
Southern Company	SO	$56.97	$2.48	4.50%	4.67%	4.84%	5.01%	5.18%	5.36%	5.53%	10.04%
Xcel Energy Inc.	XEL	$60.35	$1.62	5.50%	5.50%	5.51%	5.51%	5.52%	5.52%	5.53%	8.45%
MEAN											**9.29%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of November 29, 2019
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC 204
[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 206
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

Docket No. UE 374
Exhibit PAC/406
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Gross Domestic Product Growth

February 2020

CALCULATION OF LONG-TERM GDP GROWTH RATE

Step 1	
Real GDP ($ Billions) [1]	
1929	$ 1,109.4
2018	$ 18,638.2
Compound Annual Growth Rate	**3.22%**
Step 2	
Consumer Price Index (YoY % Change) [2]	
2026-2030	2.10%
Average	2.10%
Consumer Price Index (All-Urban) [3]	
2029	3.24
2050	5.24
Compound Annual Growth Rate	2.31%
GDP Chain-type Price Index (2009=1.000) [3]	
2029	1.50
2050	2.42
Compound Annual Growth Rate	2.29%
Average Inflation Forecast	**2.23%**
Long-Term GDP Growth Rate	**5.53%**

Notes:
[1] Bureau of Economic Analysis, November 27, 2019
[2] Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 14
[3] Energy Information Administration, Annual Energy Outlook 2019, Table 20

Docket No. UE 374
Exhibit PAC/407
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Projected Discounted Cash Flow Model

February 2020

PROJECTED CONSTANT GROWTH DCF -- PACIFICORP PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	All Proxy Group [11]	[12]	[13]	With Exclusions [14]	[15]	[16]
Company		Annualized Dividend	Stock Price (2022 - 2024) High	Low	Mean	Dividend Yield	Expected Dividend	Value Line Earnings	Yahoo! Finance	Zacks Earnings	Average Growth	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.85	$85.00	$65.00	$75.00	3.80%	3.93%	6.00%	7.00%	7.20%	6.73%	9.91%	10.66%	11.14%	9.91%	10.66%	11.14%
Alliant Energy Corporation	LNT	$1.74	$50.00	$35.00	$42.50	4.09%	4.21%	6.50%	5.00%	5.50%	5.67%	9.20%	9.88%	10.73%	9.20%	9.88%	10.73%
Ameren Corporation	AEE	$2.55	$75.00	$55.00	$65.00	3.92%	4.04%	6.50%	4.70%	6.20%	5.80%	8.72%	9.84%	10.55%	8.72%	9.84%	10.55%
American Electric Power Company, Inc.	AEP	$3.40	$95.00	$80.00	$87.50	3.89%	3.99%	4.00%	5.90%	5.60%	5.17%	7.96%	9.15%	9.90%	7.96%	9.15%	9.90%
Avista Corporation	AVA	$1.80	$55.00	$40.00	$47.50	3.79%	3.86%	3.50%	3.50%	3.40%	3.47%	7.25%	7.32%	7.36%	7.25%	7.32%	7.36%
CenterPoint Energy, Inc.	CNP	$1.35	$40.00	$25.00	$32.50	4.15%	4.30%	12.50%	3.63%	4.80%	6.98%	7.86%	11.28%	16.91%	7.86%	11.28%	16.91%
CMS Energy Corporation	CMS	$2.00	$65.00	$45.00	$55.00	3.64%	3.76%	7.00%	7.50%	6.40%	6.97%	10.15%	10.73%	11.27%	10.15%	10.73%	11.27%
Dominion Resources, Inc.	D	$4.05	$105.00	$75.00	$90.00	4.50%	4.62%	6.50%	4.41%	4.80%	5.24%	9.01%	9.85%	11.15%	9.01%	9.85%	11.15%
DTE Energy Company	DTE	$4.80	$145.00	$105.00	$125.00	3.84%	3.94%	5.50%	4.83%	6.00%	5.44%	8.76%	9.39%	9.96%	8.76%	9.39%	9.96%
Duke Energy Corporation	DUK	$4.05	$105.00	$80.00	$92.50	4.38%	4.49%	6.00%	4.65%	4.80%	5.15%	9.13%	9.64%	10.51%	9.13%	9.64%	10.51%
Entergy Corporation	ETR	$4.45	$135.00	$90.00	$112.50	3.96%	4.03%	0.50%	Negative	7.00%	3.75%	4.47%	7.78%	11.09%		7.78%	11.09%
Evergy, Inc.	EVRG	$2.50	$75.00	$55.00	$65.00	3.85%	3.97%	NMF	6.70%	6.40%	6.55%	10.37%	10.52%	10.68%	10.37%	10.52%	10.68%
FirstEnergy Corporation	FE	$1.90	$60.00	$45.00	$52.50	3.62%	3.73%	6.50%	Negative	6.00%	6.25%	9.73%	9.98%	10.24%	9.73%	9.98%	10.24%
IDACORP, Inc.	IDA	$3.35	$110.00	$80.00	$95.00	3.53%	3.58%	3.50%	2.50%	3.80%	3.27%	6.07%	6.85%	7.39%			7.39%
NextEra Energy, Inc.	NEE	$7.00	$225.00	$185.00	$205.00	3.41%	3.57%	10.50%	7.99%	8.00%	8.83%	11.54%	12.40%	14.09%	11.54%	12.40%	14.09%
NorthWestern Corporation	NWE	$2.70	$80.00	$60.00	$70.00	3.86%	3.91%	3.00%	3.20%	2.70%	2.97%	6.61%	6.88%	7.12%			7.12%
OGE Energy Corporation	OGE	$1.90	$55.00	$40.00	$47.50	4.00%	4.10%	6.50%	3.50%	4.50%	4.83%	7.57%	8.93%	10.63%	7.57%	8.93%	10.63%
Otter Tail Corporation	OTTR	$1.65	$55.00	$40.00	$47.50	3.47%	3.60%	5.00%	9.00%	7.00%	7.00%	8.56%	10.60%	12.63%	8.56%	10.60%	12.63%
Pinnacle West Capital Corporation	PNW	$3.80	$110.00	$90.00	$100.00	3.80%	3.89%	5.00%	4.41%	4.90%	4.77%	8.29%	8.66%	8.90%	8.29%	8.66%	8.90%
PNM Resources, Inc.	PNM	$1.50	$55.00	$35.00	$45.00	3.33%	3.44%	7.00%	6.35%	5.60%	6.32%	9.03%	9.76%	10.45%	9.03%	9.76%	10.45%
Portland General Electric Company	POR	$1.95	$60.00	$45.00	$52.50	3.71%	3.80%	4.50%	4.10%	4.50%	4.37%	7.89%	8.16%	8.30%	7.89%	8.16%	8.30%
PPL Corporation	PPL	$1.80	$45.00	$35.00	$40.00	4.50%	4.52%	1.50%	0.50%	NA%	1.00%	5.01%	5.52%	6.03%			
Southern Company	SO	$2.78	$70.00	$50.00	$60.00	4.63%	4.71%	3.50%	1.56%	4.50%	3.19%	6.23%	7.89%	9.24%		7.89%	9.24%
Xcel Energy Inc.	XEL	$2.05	$65.00	$50.00	$57.50	3.57%	3.66%	5.50%	5.20%	5.40%	5.37%	8.86%	9.03%	9.16%	8.86%	9.03%	9.16%
Mean						3.88%	3.98%	5.50%	4.82%	5.43%	5.21%	8.26%	9.20%	10.23%	8.94%	9.59%	10.41%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals Average ([2], [3])
[5] Equals [1] / [4]
[6] Equals [5] x (1 + 0.50 x [10])
[7] Source: Value Line
[8] Source: Yahoo! Finance
[9] Source: Zacks
[10] Equals Average ([7], [8], [9])
[11] Equals [5] x (1 + 0.50 x Minimum ([7], [8], [9]) + Minimum ([7], [8], [9])
[12] Equals [6] + [10]
[13] Equals [5] x (1 + 0.50 x Maximum ([7], [8], [9]) + Maximum ([7], [8], [9])
[14] Equals [11] if greater than 7.00%
[15] Equals [12] if greater than 7.00%
[16] Equals [13] if greater than 7.00%

Docket No. UE 374
Exhibit PAC/408
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Capital Asset Pricing Model

February 2020

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA

K = Rf + β (Rm − Rf)

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE
ALLETE, Inc.	ALE	2.28%	0.65	12.60%	10.32%	8.98%	9.89%
Alliant Energy Corporation	LNT	2.28%	0.60	12.60%	10.32%	8.47%	9.50%
Ameren Corporation	AEE	2.28%	0.55	12.60%	10.32%	7.95%	9.11%
American Electric Power Company, Inc.	AEP	2.28%	0.55	12.60%	10.32%	7.95%	9.11%
Avista Corporation	AVA	2.28%	0.60	12.60%	10.32%	8.47%	9.50%
CenterPoint Energy, Inc.	CNP	2.28%	0.80	12.60%	10.32%	10.53%	11.05%
CMS Energy Corporation	CMS	2.28%	0.55	12.60%	10.32%	7.95%	9.11%
Dominion Resources, Inc.	D	2.28%	0.55	12.60%	10.32%	7.95%	9.11%
DTE Energy Company	DTE	2.28%	0.55	12.60%	10.32%	7.95%	9.11%
Duke Energy Corporation	DUK	2.28%	0.50	12.60%	10.32%	7.44%	8.73%
Entergy Corporation	ETR	2.28%	0.60	12.60%	10.32%	8.47%	9.50%
Evergy, Inc.	EVRG	2.28%	NMF	12.60%	10.32%		
FirstEnergy Corporation	FE	2.28%	0.65	12.60%	10.32%	8.98%	9.89%
IDACORP, Inc.	IDA	2.28%	0.55	12.60%	10.32%	7.95%	9.11%
NextEra Energy, Inc.	NEE	2.28%	0.55	12.60%	10.32%	7.95%	9.11%
NorthWestern Corporation	NWE	2.28%	0.60	12.60%	10.32%	8.47%	9.50%
OGE Energy Corporation	OGE	2.28%	0.80	12.60%	10.32%	10.53%	11.05%
Otter Tail Corporation	OTTR	2.28%	0.65	12.60%	10.32%	8.98%	9.89%
Pinnacle West Capital Corporation	PNW	2.28%	0.55	12.60%	10.32%	7.95%	9.11%
PNM Resources, Inc.	PNM	2.28%	0.60	12.60%	10.32%	8.47%	9.50%
Portland General Electric Company	POR	2.28%	0.60	12.60%	10.32%	8.47%	9.50%
PPL Corporation	PPL	2.28%	0.70	12.60%	10.32%	9.50%	10.28%
Southern Company	SO	2.28%	0.50	12.60%	10.32%	7.44%	8.73%
Xcel Energy Inc.	XEL	2.28%	0.50	12.60%	10.32%	7.44%	8.73%
Mean						8.45%	9.48%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line
[3] Source: Exhibit PAC/208, page 7 (Analysts Long-term growth estimates)
[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 = Rf + β (Rm − Rf)

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q1 2020 - Q1 2021)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE
ALLETE, Inc.	ALE	2.36%	0.65	12.60%	10.24%	9.01%	9.91%
Alliant Energy Corporation	LNT	2.36%	0.60	12.60%	10.24%	8.50%	9.53%
Ameren Corporation	AEE	2.36%	0.55	12.60%	10.24%	7.99%	9.14%
American Electric Power Company, Inc.	AEP	2.36%	0.55	12.60%	10.24%	7.99%	9.14%
Avista Corporation	AVA	2.36%	0.60	12.60%	10.24%	8.50%	9.53%
CenterPoint Energy, Inc.	CNP	2.36%	0.80	12.60%	10.24%	10.55%	11.06%
CMS Energy Corporation	CMS	2.36%	0.55	12.60%	10.24%	7.99%	9.14%
Dominion Resources, Inc.	D	2.36%	0.55	12.60%	10.24%	7.99%	9.14%
DTE Energy Company	DTE	2.36%	0.55	12.60%	10.24%	7.99%	9.14%
Duke Energy Corporation	DUK	2.36%	0.50	12.60%	10.24%	7.48%	8.76%
Entergy Corporation	ETR	2.36%	0.60	12.60%	10.24%	8.50%	9.53%
Evergy, Inc.	EVRG	2.36%	NMF	12.60%	10.24%		
FirstEnergy Corporation	FE	2.36%	0.65	12.60%	10.24%	9.01%	9.91%
IDACORP, Inc.	IDA	2.36%	0.55	12.60%	10.24%	7.99%	9.14%
NextEra Energy, Inc.	NEE	2.36%	0.55	12.60%	10.24%	7.99%	9.14%
NorthWestern Corporation	NWE	2.36%	0.60	12.60%	10.24%	8.50%	9.53%
OGE Energy Corporation	OGE	2.36%	0.80	12.60%	10.24%	10.55%	11.06%
Otter Tail Corporation	OTTR	2.36%	0.65	12.60%	10.24%	9.01%	9.91%
Pinnacle West Capital Corporation	PNW	2.36%	0.55	12.60%	10.24%	7.99%	9.14%
PNM Resources, Inc.	PNM	2.36%	0.60	12.60%	10.24%	8.50%	9.53%
Portland General Electric Company	POR	2.36%	0.60	12.60%	10.24%	8.50%	9.53%
PPL Corporation	PPL	2.36%	0.70	12.60%	10.24%	9.53%	10.29%
Southern Company	SO	2.36%	0.50	12.60%	10.24%	7.48%	8.76%
Xcel Energy Inc.	XEL	2.36%	0.50	12.60%	10.24%	7.48%	8.76%
Mean						8.48%	9.51%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 2
[2] Source: Value Line
[3] Source: Exhibit PAC/208, page 7 (Analysts Long-term growth estimates)
[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 = Rf + β (Rm − Rf)

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2021 - 2025)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE
ALLETE, Inc.	ALE	3.20%	0.65	12.60%	9.40%	9.31%	10.13%
Alliant Energy Corporation	LNT	3.20%	0.60	12.60%	9.40%	8.84%	9.78%
Ameren Corporation	AEE	3.20%	0.55	12.60%	9.40%	8.37%	9.43%
American Electric Power Company, Inc.	AEP	3.20%	0.55	12.60%	9.40%	8.37%	9.43%
Avista Corporation	AVA	3.20%	0.60	12.60%	9.40%	8.84%	9.78%
CenterPoint Energy, Inc.	CNP	3.20%	0.80	12.60%	9.40%	10.72%	11.19%
CMS Energy Corporation	CMS	3.20%	0.55	12.60%	9.40%	8.37%	9.43%
Dominion Resources, Inc.	D	3.20%	0.55	12.60%	9.40%	8.37%	9.43%
DTE Energy Company	DTE	3.20%	0.55	12.60%	9.40%	8.37%	9.43%
Duke Energy Corporation	DUK	3.20%	0.50	12.60%	9.40%	7.90%	9.07%
Entergy Corporation	ETR	3.20%	0.60	12.60%	9.40%	8.84%	9.78%
Evergy, Inc.	EVRG	3.20%	NMF	12.60%	9.40%		
FirstEnergy Corporation	FE	3.20%	0.65	12.60%	9.40%	9.31%	10.13%
IDACORP, Inc.	IDA	3.20%	0.55	12.60%	9.40%	8.37%	9.43%
NextEra Energy, Inc.	NEE	3.20%	0.55	12.60%	9.40%	8.37%	9.43%
NorthWestern Corporation	NWE	3.20%	0.60	12.60%	9.40%	8.84%	9.78%
OGE Energy Corporation	OGE	3.20%	0.80	12.60%	9.40%	10.72%	11.19%
Otter Tail Corporation	OTTR	3.20%	0.65	12.60%	9.40%	9.31%	10.13%
Pinnacle West Capital Corporation	PNW	3.20%	0.55	12.60%	9.40%	8.37%	9.43%
PNM Resources, Inc.	PNM	3.20%	0.60	12.60%	9.40%	8.84%	9.78%
Portland General Electric Company	POR	3.20%	0.60	12.60%	9.40%	8.84%	9.78%
PPL Corporation	PPL	3.20%	0.70	12.60%	9.40%	9.78%	10.48%
Southern Company	SO	3.20%	0.50	12.60%	9.40%	7.90%	9.07%
Xcel Energy Inc.	XEL	3.20%	0.50	12.60%	9.40%	7.90%	9.07%
Mean						8.82%	9.76%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 14
[2] Source: Value Line
[3] Source: Exhibit PAC/208, page 7 (Analysts Long-term growth estimates)
[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 = Rf + β (Rm − Rf)

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE
ALLETE, Inc.	ALE	2.28%	0.71	12.60%	10.32%	9.56%	10.32%
Alliant Energy Corporation	LNT	2.28%	0.69	12.60%	10.32%	9.36%	10.17%
Ameren Corporation	AEE	2.28%	0.64	12.60%	10.32%	8.93%	9.84%
American Electric Power Company, Inc.	AEP	2.28%	0.62	12.60%	10.32%	8.71%	9.68%
Avista Corporation	AVA	2.28%	0.69	12.60%	10.32%	9.43%	10.22%
CenterPoint Energy, Inc.	CNP	2.28%	0.73	12.60%	10.32%	9.78%	10.48%
CMS Energy Corporation	CMS	2.28%	0.64	12.60%	10.32%	8.89%	9.82%
Dominion Resources, Inc.	D	2.28%	0.60	12.60%	10.32%	8.42%	9.46%
DTE Energy Company	DTE	2.28%	0.66	12.60%	10.32%	9.07%	9.95%
Duke Energy Corporation	DUK	2.28%	0.53	12.60%	10.32%	7.76%	8.97%
Entergy Corporation	ETR	2.28%	0.64	12.60%	10.32%	8.92%	9.84%
Evergy, Inc.	EVRG	2.28%	0.63	12.60%	10.32%	8.75%	9.71%
FirstEnergy Corporation	FE	2.28%	0.68	12.60%	10.32%	9.28%	10.11%
IDACORP, Inc.	IDA	2.28%	0.73	12.60%	10.32%	9.78%	10.49%
NextEra Energy, Inc.	NEE	2.28%	0.63	12.60%	10.32%	8.81%	9.76%
NorthWestern Corporation	NWE	2.28%	0.70	12.60%	10.32%	9.53%	10.29%
OGE Energy Corporation	OGE	2.28%	0.74	12.60%	10.32%	9.92%	10.59%
Otter Tail Corporation	OTTR	2.28%	0.79	12.60%	10.32%	10.47%	11.00%
Pinnacle West Capital Corporation	PNW	2.28%	0.65	12.60%	10.32%	8.97%	9.88%
PNM Resources, Inc.	PNM	2.28%	0.73	12.60%	10.32%	9.81%	10.51%
Portland General Electric Company	POR	2.28%	0.67	12.60%	10.32%	9.14%	10.01%
PPL Corporation	PPL	2.28%	0.63	12.60%	10.32%	8.76%	9.72%
Southern Company	SO	2.28%	0.52	12.60%	10.32%	7.69%	8.92%
Xcel Energy Inc.	XEL	2.28%	0.57	12.60%	10.32%	8.18%	9.28%
Mean						9.08%	9.96%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/208, page 7 (Analysts Long-term growth estimates)
[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 = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2021 - 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	2.36%	0.71	12.60%	10.24%	9.58%	10.34%
Alliant Energy Corporation	LNT	2.36%	0.69	12.60%	10.24%	9.39%	10.19%
Ameren Corporation	AEE	2.36%	0.64	12.60%	10.24%	8.96%	9.87%
American Electric Power Company, Inc.	AEP	2.36%	0.62	12.60%	10.24%	8.74%	9.71%
Avista Corporation	AVA	2.36%	0.69	12.60%	10.24%	9.46%	10.24%
CenterPoint Energy, Inc.	CNP	2.36%	0.73	12.60%	10.24%	9.80%	10.50%
CMS Energy Corporation	CMS	2.36%	0.64	12.60%	10.24%	8.92%	9.84%
Dominion Resources, Inc.	D	2.36%	0.60	12.60%	10.24%	8.45%	9.49%
DTE Energy Company	DTE	2.36%	0.66	12.60%	10.24%	9.10%	9.97%
Duke Energy Corporation	DUK	2.36%	0.53	12.60%	10.24%	7.80%	9.00%
Entergy Corporation	ETR	2.36%	0.64	12.60%	10.24%	8.95%	9.86%
Evergy, Inc.	EVRG	2.36%	0.63	12.60%	10.24%	8.78%	9.73%
FirstEnergy Corporation	FE	2.36%	0.68	12.60%	10.24%	9.31%	10.13%
IDACORP, Inc.	IDA	2.36%	0.73	12.60%	10.24%	9.80%	10.50%
NextEra Energy, Inc.	NEE	2.36%	0.63	12.60%	10.24%	8.84%	9.78%
NorthWestern Corporation	NWE	2.36%	0.70	12.60%	10.24%	9.55%	10.31%
OGE Energy Corporation	OGE	2.36%	0.74	12.60%	10.24%	9.95%	10.61%
Otter Tail Corporation	OTTR	2.36%	0.79	12.60%	10.24%	10.49%	11.02%
Pinnacle West Capital Corporation	PNW	2.36%	0.65	12.60%	10.24%	9.00%	9.90%
PNM Resources, Inc.	PNM	2.36%	0.73	12.60%	10.24%	9.83%	10.53%
Portland General Electric Company	POR	2.36%	0.67	12.60%	10.24%	9.17%	10.03%
PPL Corporation	PPL	2.36%	0.63	12.60%	10.24%	8.79%	9.74%
Southern Company	SO	2.36%	0.52	12.60%	10.24%	7.73%	8.95%
Xcel Energy Inc.	XEL	2.36%	0.57	12.60%	10.24%	8.22%	9.31%
Mean						9.11%	9.98%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 2
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/208, page 7 (Analysts Long-term growth estimates)
[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 = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2021 - 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	3.20%	0.71	12.60%	9.40%	9.83%	10.52%
Alliant Energy Corporation	LNT	3.20%	0.69	12.60%	9.40%	9.65%	10.39%
Ameren Corporation	AEE	3.20%	0.64	12.60%	9.40%	9.26%	10.09%
American Electric Power Company, Inc.	AEP	3.20%	0.62	12.60%	9.40%	9.06%	9.94%
Avista Corporation	AVA	3.20%	0.69	12.60%	9.40%	9.71%	10.44%
CenterPoint Energy, Inc.	CNP	3.20%	0.73	12.60%	9.40%	10.03%	10.67%
CMS Energy Corporation	CMS	3.20%	0.64	12.60%	9.40%	9.22%	10.07%
Dominion Resources, Inc.	D	3.20%	0.60	12.60%	9.40%	8.79%	9.74%
DTE Energy Company	DTE	3.20%	0.66	12.60%	9.40%	9.39%	10.19%
Duke Energy Corporation	DUK	3.20%	0.53	12.60%	9.40%	8.19%	9.29%
Entergy Corporation	ETR	3.20%	0.64	12.60%	9.40%	9.25%	10.08%
Evergy, Inc.	EVRG	3.20%	0.63	12.60%	9.40%	9.09%	9.97%
FirstEnergy Corporation	FE	3.20%	0.68	12.60%	9.40%	9.58%	10.33%
IDACORP, Inc.	IDA	3.20%	0.73	12.60%	9.40%	10.03%	10.67%
NextEra Energy, Inc.	NEE	3.20%	0.63	12.60%	9.40%	9.15%	10.01%
NorthWestern Corporation	NWE	3.20%	0.70	12.60%	9.40%	9.80%	10.50%
OGE Energy Corporation	OGE	3.20%	0.74	12.60%	9.40%	10.16%	10.77%
Otter Tail Corporation	OTTR	3.20%	0.79	12.60%	9.40%	10.66%	11.15%
Pinnacle West Capital Corporation	PNW	3.20%	0.65	12.60%	9.40%	9.30%	10.12%
PNM Resources, Inc.	PNM	3.20%	0.73	12.60%	9.40%	10.06%	10.70%
Portland General Electric Company	POR	3.20%	0.67	12.60%	9.40%	9.45%	10.24%
PPL Corporation	PPL	3.20%	0.63	12.60%	9.40%	9.11%	9.98%
Southern Company	SO	3.20%	0.52	12.60%	9.40%	8.13%	9.25%
Xcel Energy Inc.	XEL	3.20%	0.57	12.60%	9.40%	8.58%	9.58%
Mean						9.40%	10.20%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 14
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/208, page 7 (Analysts Long-term growth estimates)
[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 & VL BETA

$K = Rf + \beta (Rm - Rf)$

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE
ALLETE, Inc.	ALE	2.28%	0.65	13.58%	11.30%	9.62%	10.61%
Alliant Energy Corporation	LNT	2.28%	0.60	13.58%	11.30%	9.06%	10.19%
Ameren Corporation	AEE	2.28%	0.55	13.58%	11.30%	8.49%	9.76%
American Electric Power Company, Inc.	AEP	2.28%	0.55	13.58%	11.30%	8.49%	9.76%
Avista Corporation	AVA	2.28%	0.60	13.58%	11.30%	9.06%	10.19%
CenterPoint Energy, Inc.	CNP	2.28%	0.80	13.58%	11.30%	11.32%	11.88%
CMS Energy Corporation	CMS	2.28%	0.55	13.58%	11.30%	8.49%	9.76%
Dominion Resources, Inc.	D	2.28%	0.55	13.58%	11.30%	8.49%	9.76%
DTE Energy Company	DTE	2.28%	0.55	13.58%	11.30%	8.49%	9.76%
Duke Energy Corporation	DUK	2.28%	0.50	13.58%	11.30%	7.93%	9.34%
Entergy Corporation	ETR	2.28%	0.60	13.58%	11.30%	9.06%	10.19%
Evergy, Inc.	EVRG	2.28%	NMF	13.58%	11.30%		
FirstEnergy Corporation	FE	2.28%	0.65	13.58%	11.30%	9.62%	10.61%
IDACORP, Inc.	IDA	2.28%	0.55	13.58%	11.30%	8.49%	9.76%
NextEra Energy, Inc.	NEE	2.28%	0.55	13.58%	11.30%	8.49%	9.76%
NorthWestern Corporation	NWE	2.28%	0.60	13.58%	11.30%	9.06%	10.19%
OGE Energy Corporation	OGE	2.28%	0.80	13.58%	11.30%	11.32%	11.88%
Otter Tail Corporation	OTTR	2.28%	0.65	13.58%	11.30%	9.62%	10.61%
Pinnacle West Capital Corporation	PNW	2.28%	0.55	13.58%	11.30%	8.49%	9.76%
PNM Resources, Inc.	PNM	2.28%	0.60	13.58%	11.30%	9.06%	10.19%
Portland General Electric Company	POR	2.28%	0.60	13.58%	11.30%	9.06%	10.19%
PPL Corporation	PPL	2.28%	0.70	13.58%	11.30%	10.19%	11.03%
Southern Company	SO	2.28%	0.50	13.58%	11.30%	7.93%	9.34%
Xcel Energy Inc.	XEL	2.28%	0.50	13.58%	11.30%	7.93%	9.34%
Mean						9.03%	10.17%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line
[3] Source: Exhibit PAC/208, page 7 (S&P Earnings and Estimates Report)
[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

$K = Rf + \beta (Rm - Rf)$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q1 2020 - Q1 2021)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE
ALLETE, Inc.	ALE	2.36%	0.65	13.58%	11.22%	9.65%	10.63%
Alliant Energy Corporation	LNT	2.36%	0.60	13.58%	11.22%	9.09%	10.21%
Ameren Corporation	AEE	2.36%	0.55	13.58%	11.22%	8.53%	9.79%
American Electric Power Company, Inc.	AEP	2.36%	0.55	13.58%	11.22%	8.53%	9.79%
Avista Corporation	AVA	2.36%	0.60	13.58%	11.22%	9.09%	10.21%
CenterPoint Energy, Inc.	CNP	2.36%	0.80	13.58%	11.22%	11.33%	11.89%
CMS Energy Corporation	CMS	2.36%	0.55	13.58%	11.22%	8.53%	9.79%
Dominion Resources, Inc.	D	2.36%	0.55	13.58%	11.22%	8.53%	9.79%
DTE Energy Company	DTE	2.36%	0.55	13.58%	11.22%	8.53%	9.79%
Duke Energy Corporation	DUK	2.36%	0.50	13.58%	11.22%	7.97%	9.37%
Entergy Corporation	ETR	2.36%	0.60	13.58%	11.22%	9.09%	10.21%
Evergy, Inc.	EVRG	2.36%	NMF	13.58%	11.22%		
FirstEnergy Corporation	FE	2.36%	0.65	13.58%	11.22%	9.65%	10.63%
IDACORP, Inc.	IDA	2.36%	0.55	13.58%	11.22%	8.53%	9.79%
NextEra Energy, Inc.	NEE	2.36%	0.55	13.58%	11.22%	8.53%	9.79%
NorthWestern Corporation	NWE	2.36%	0.60	13.58%	11.22%	9.09%	10.21%
OGE Energy Corporation	OGE	2.36%	0.80	13.58%	11.22%	11.33%	11.89%
Otter Tail Corporation	OTTR	2.36%	0.65	13.58%	11.22%	9.65%	10.63%
Pinnacle West Capital Corporation	PNW	2.36%	0.55	13.58%	11.22%	8.53%	9.79%
PNM Resources, Inc.	PNM	2.36%	0.60	13.58%	11.22%	9.09%	10.21%
Portland General Electric Company	POR	2.36%	0.60	13.58%	11.22%	9.09%	10.21%
PPL Corporation	PPL	2.36%	0.70	13.58%	11.22%	10.21%	11.05%
Southern Company	SO	2.36%	0.50	13.58%	11.22%	7.97%	9.37%
Xcel Energy Inc.	XEL	2.36%	0.50	13.58%	11.22%	7.97%	9.37%
Mean						9.07%	10.19%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 2
[2] Source: Value Line
[3] Source: Exhibit PAC/208, page 7 (S&P Earnings and Estimates Report)
[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 = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2021 - 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	3.20%	0.65	13.58%	10.38%	9.94%	10.85%
Alliant Energy Corporation	LNT	3.20%	0.60	13.58%	10.38%	9.43%	10.46%
Ameren Corporation	AEE	3.20%	0.55	13.58%	10.38%	8.91%	10.07%
American Electric Power Company, Inc.	AEP	3.20%	0.55	13.58%	10.38%	8.91%	10.07%
Avista Corporation	AVA	3.20%	0.60	13.58%	10.38%	9.43%	10.46%
CenterPoint Energy, Inc.	CNP	3.20%	0.80	13.58%	10.38%	11.50%	12.02%
CMS Energy Corporation	CMS	3.20%	0.55	13.58%	10.38%	8.91%	10.07%
Dominion Resources, Inc.	D	3.20%	0.55	13.58%	10.38%	8.91%	10.07%
DTE Energy Company	DTE	3.20%	0.55	13.58%	10.38%	8.91%	10.07%
Duke Energy Corporation	DUK	3.20%	0.50	13.58%	10.38%	8.39%	9.69%
Entergy Corporation	ETR	3.20%	0.60	13.58%	10.38%	9.43%	10.46%
Evergy, Inc.	EVRG	3.20%	NMF	13.58%	10.38%		
FirstEnergy Corporation	FE	3.20%	0.65	13.58%	10.38%	9.94%	10.85%
IDACORP, Inc.	IDA	3.20%	0.55	13.58%	10.38%	8.91%	10.07%
NextEra Energy, Inc.	NEE	3.20%	0.55	13.58%	10.38%	8.91%	10.07%
NorthWestern Corporation	NWE	3.20%	0.60	13.58%	10.38%	9.43%	10.46%
OGE Energy Corporation	OGE	3.20%	0.80	13.58%	10.38%	11.50%	12.02%
Otter Tail Corporation	OTTR	3.20%	0.65	13.58%	10.38%	9.94%	10.85%
Pinnacle West Capital Corporation	PNW	3.20%	0.55	13.58%	10.38%	8.91%	10.07%
PNM Resources, Inc.	PNM	3.20%	0.60	13.58%	10.38%	9.43%	10.46%
Portland General Electric Company	POR	3.20%	0.60	13.58%	10.38%	9.43%	10.46%
PPL Corporation	PPL	3.20%	0.70	13.58%	10.38%	10.46%	11.24%
Southern Company	SO	3.20%	0.50	13.58%	10.38%	8.39%	9.69%
Xcel Energy Inc.	XEL	3.20%	0.50	13.58%	10.38%	8.39%	9.69%
Mean						9.40%	10.45%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 14
[2] Source: Value Line
[3] Source: Exhibit PAC/208, page 7 (S&P Earnings and Estimates Report)
[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 = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	2.28%	0.71	13.58%	11.30%	10.25%	11.08%
Alliant Energy Corporation	LNT	2.28%	0.69	13.58%	11.30%	10.04%	10.92%
Ameren Corporation	AEE	2.28%	0.64	13.58%	11.30%	9.56%	10.56%
American Electric Power Company, Inc.	AEP	2.28%	0.62	13.58%	11.30%	9.32%	10.39%
Avista Corporation	AVA	2.28%	0.69	13.58%	11.30%	10.11%	10.98%
CenterPoint Energy, Inc.	CNP	2.28%	0.73	13.58%	11.30%	10.49%	11.26%
CMS Energy Corporation	CMS	2.28%	0.64	13.58%	11.30%	9.52%	10.53%
Dominion Resources, Inc.	D	2.28%	0.60	13.58%	11.30%	9.00%	10.15%
DTE Energy Company	DTE	2.28%	0.66	13.58%	11.30%	9.72%	10.68%
Duke Energy Corporation	DUK	2.28%	0.53	13.58%	11.30%	8.28%	9.60%
Entergy Corporation	ETR	2.28%	0.64	13.58%	11.30%	9.55%	10.55%
Evergy, Inc.	EVRG	2.28%	0.63	13.58%	11.30%	9.36%	10.41%
FirstEnergy Corporation	FE	2.28%	0.68	13.58%	11.30%	9.94%	10.85%
IDACORP, Inc.	IDA	2.28%	0.73	13.58%	11.30%	10.49%	11.26%
NextEra Energy, Inc.	NEE	2.28%	0.63	13.58%	11.30%	9.43%	10.47%
NorthWestern Corporation	NWE	2.28%	0.70	13.58%	11.30%	10.21%	11.05%
OGE Energy Corporation	OGE	2.28%	0.74	13.58%	11.30%	10.65%	11.38%
Otter Tail Corporation	OTTR	2.28%	0.79	13.58%	11.30%	11.25%	11.83%
Pinnacle West Capital Corporation	PNW	2.28%	0.65	13.58%	11.30%	9.61%	10.60%
PNM Resources, Inc.	PNM	2.28%	0.73	13.58%	11.30%	10.53%	11.29%
Portland General Electric Company	POR	2.28%	0.67	13.58%	11.30%	9.79%	10.74%
PPL Corporation	PPL	2.28%	0.63	13.58%	11.30%	9.38%	10.43%
Southern Company	SO	2.28%	0.52	13.58%	11.30%	8.20%	9.55%
Xcel Energy Inc.	XEL	2.28%	0.57	13.58%	11.30%	8.74%	9.95%
Mean						9.73%	10.69%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/208, page 7 (S&P Earnings and Estimates Report)
[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

$K = Rf + \beta\ (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2021 - 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	2.36%	0.71	13.58%	11.22%	10.27%	11.10%
Alliant Energy Corporation	LNT	2.36%	0.69	13.58%	11.22%	10.06%	10.94%
Ameren Corporation	AEE	2.36%	0.64	13.58%	11.22%	9.59%	10.59%
American Electric Power Company, Inc.	AEP	2.36%	0.62	13.58%	11.22%	9.35%	10.41%
Avista Corporation	AVA	2.36%	0.69	13.58%	11.22%	10.14%	11.00%
CenterPoint Energy, Inc.	CNP	2.36%	0.73	13.58%	11.22%	10.51%	11.28%
CMS Energy Corporation	CMS	2.36%	0.64	13.58%	11.22%	9.55%	10.55%
Dominion Resources, Inc.	D	2.36%	0.60	13.58%	11.22%	9.04%	10.17%
DTE Energy Company	DTE	2.36%	0.66	13.58%	11.22%	9.74%	10.70%
Duke Energy Corporation	DUK	2.36%	0.53	13.58%	11.22%	8.32%	9.63%
Entergy Corporation	ETR	2.36%	0.64	13.58%	11.22%	9.58%	10.58%
Evergy, Inc.	EVRG	2.36%	0.63	13.58%	11.22%	9.39%	10.44%
FirstEnergy Corporation	FE	2.36%	0.68	13.58%	11.22%	9.97%	10.87%
IDACORP, Inc.	IDA	2.36%	0.73	13.58%	11.22%	10.52%	11.28%
NextEra Energy, Inc.	NEE	2.36%	0.63	13.58%	11.22%	9.46%	10.49%
NorthWestern Corporation	NWE	2.36%	0.70	13.58%	11.22%	10.24%	11.07%
OGE Energy Corporation	OGE	2.36%	0.74	13.58%	11.22%	10.67%	11.40%
Otter Tail Corporation	OTTR	2.36%	0.79	13.58%	11.22%	11.27%	11.84%
Pinnacle West Capital Corporation	PNW	2.36%	0.65	13.58%	11.22%	9.64%	10.62%
PNM Resources, Inc.	PNM	2.36%	0.73	13.58%	11.22%	10.55%	11.31%
Portland General Electric Company	POR	2.36%	0.67	13.58%	11.22%	9.82%	10.76%
PPL Corporation	PPL	2.36%	0.63	13.58%	11.22%	9.41%	10.45%
Southern Company	SO	2.36%	0.52	13.58%	11.22%	8.24%	9.58%
Xcel Energy Inc.	XEL	2.36%	0.57	13.58%	11.22%	8.78%	9.98%
Mean						9.75%	10.71%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 2
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/208, page 7 (S&P Earnings and Estimates Report)
[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

$K = Rf + \beta\ (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2021 - 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE
ALLETE, Inc.	ALE	3.20%	0.71	13.58%	10.38%	10.52%	11.28%
Alliant Energy Corporation	LNT	3.20%	0.69	13.58%	10.38%	10.33%	11.14%
Ameren Corporation	AEE	3.20%	0.64	13.58%	10.38%	9.89%	10.81%
American Electric Power Company, Inc.	AEP	3.20%	0.62	13.58%	10.38%	9.67%	10.65%
Avista Corporation	AVA	3.20%	0.69	13.58%	10.38%	10.39%	11.19%
CenterPoint Energy, Inc.	CNP	3.20%	0.73	13.58%	10.38%	10.74%	11.45%
CMS Energy Corporation	CMS	3.20%	0.64	13.58%	10.38%	9.85%	10.78%
Dominion Resources, Inc.	D	3.20%	0.60	13.58%	10.38%	9.38%	10.43%
DTE Energy Company	DTE	3.20%	0.66	13.58%	10.38%	10.03%	10.92%
Duke Energy Corporation	DUK	3.20%	0.53	13.58%	10.38%	8.71%	9.93%
Entergy Corporation	ETR	3.20%	0.64	13.58%	10.38%	9.88%	10.80%
Evergy, Inc.	EVRG	3.20%	0.63	13.58%	10.38%	9.71%	10.67%
FirstEnergy Corporation	FE	3.20%	0.68	13.58%	10.38%	10.24%	11.07%
IDACORP, Inc.	IDA	3.20%	0.73	13.58%	10.38%	10.75%	11.45%
NextEra Energy, Inc.	NEE	3.20%	0.63	13.58%	10.38%	9.77%	10.72%
NorthWestern Corporation	NWE	3.20%	0.70	13.58%	10.38%	10.49%	11.26%
OGE Energy Corporation	OGE	3.20%	0.74	13.58%	10.38%	10.89%	11.56%
Otter Tail Corporation	OTTR	3.20%	0.79	13.58%	10.38%	11.44%	11.97%
Pinnacle West Capital Corporation	PNW	3.20%	0.65	13.58%	10.38%	9.93%	10.84%
PNM Resources, Inc.	PNM	3.20%	0.73	13.58%	10.38%	10.78%	11.48%
Portland General Electric Company	POR	3.20%	0.67	13.58%	10.38%	10.10%	10.97%
PPL Corporation	PPL	3.20%	0.63	13.58%	10.38%	9.72%	10.68%
Southern Company	SO	3.20%	0.52	13.58%	10.38%	8.64%	9.88%
Xcel Energy Inc.	XEL	3.20%	0.57	13.58%	10.38%	9.14%	10.25%
Mean						10.04%	10.92%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 14
[2] Source: Bloomberg Professional
[3] Source: Exhibit PAC/208, page 7 (S&P Earnings and Estimates Report)
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

MARKET RISK PREMIUM DERIVED FROM S&P EARNINGS AND ESTIMATE REPORT

[7] S&P's estimate of the S&P 500 Dividend Yield	1.90%
[8] S&P's estimate of the S&P 500 Growth Rate	11.56%
[9] S&P 500 Estimated Required Market Return	13.58%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[10] Estimated Weighted Average Dividend Yield	1.89%
[11] Estimated Weighted Average Long-Term Growth Rate	10.61%
[12] S&P 500 Estimated Required Market Return	12.60%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	0.11%	4.54%	0.01%	6.40%	0.01%
American Express Co	AXP	0.36%	1.43%	0.01%	9.52%	0.03%
Verizon Communications Inc	VZ	0.92%	4.08%	0.04%	2.66%	0.02%
Broadcom Inc	AVGO	0.46%	3.35%	0.02%	13.84%	0.06%
Boeing Co/The	BA	0.76%	2.24%	0.02%	8.81%	0.07%
Caterpillar Inc	CAT	0.30%	2.85%	0.01%	12.98%	0.04%
JPMorgan Chase & Co	JPM	1.53%	2.73%	0.04%	4.80%	0.07%
Chevron Corp	CVX	0.82%	4.06%	0.03%	2.45%	0.02%
Coca-Cola Co/The	KO	0.85%	3.00%	0.03%	6.04%	0.05%
AbbVie Inc	ABBV	0.48%	5.38%	0.03%	5.15%	0.02%
Walt Disney Co/The	DIS	1.01%	1.16%	0.01%	0.47%	0.00%
FleetCor Technologies Inc	FLT	0.10%	n/a	n/a	15.57%	0.02%
Extra Space Storage Inc	EXR	0.05%	3.39%	0.00%	4.88%	0.00%
Exxon Mobil Corp	XOM	1.07%	5.11%	0.05%	7.31%	0.08%
Phillips 66	PSX	0.19%	3.14%	0.01%	-0.11%	0.00%
General Electric Co	GE	0.36%	0.35%	0.00%	7.27%	0.03%
HP Inc	HPQ	0.11%	3.51%	0.00%	0.52%	0.00%
Home Depot Inc/The	HD	0.89%	2.47%	0.02%	9.26%	0.08%
International Business Machines Corp	IBM	0.44%	4.82%	0.02%	0.29%	0.00%
Concho Resources Inc	CXO	0.05%	0.69%	0.00%	8.23%	0.00%
Johnson & Johnson	JNJ	1.34%	2.76%	0.04%	5.31%	0.07%
McDonald's Corp	MCD	0.54%	2.57%	0.01%	8.53%	0.05%
Merck & Co Inc	MRK	0.82%	2.80%	0.02%	10.29%	0.08%
3M Co	MMM	0.36%	3.39%	0.01%	7.00%	0.03%
American Water Works Co Inc	AWK	0.08%	1.65%	0.00%	8.85%	0.01%
Bank of America Corp	BAC	1.11%	2.16%	0.02%	9.35%	0.10%
Baker Hughes Co	BKR	0.05%	3.21%	0.00%	32.26%	0.02%
Pfizer Inc	PFE	0.79%	3.74%	0.03%	3.31%	0.03%
Procter & Gamble Co/The	PG	1.12%	2.44%	0.03%	7.33%	0.08%
AT&T Inc	T	1.01%	5.46%	0.06%	5.61%	0.06%
Travelers Cos Inc/The	TRV	0.13%	2.40%	0.00%	11.75%	0.02%
United Technologies Corp	UTX	0.47%	1.98%	0.01%	9.75%	0.05%
Analog Devices Inc	ADI	0.15%	1.91%	0.00%	9.70%	0.01%
Walmart Inc	WMT	1.25%	1.78%	0.02%	5.48%	0.07%
Cisco Systems Inc	CSCO	0.71%	3.09%	0.02%	5.40%	0.04%
Intel Corp	INTC	0.93%	2.17%	0.02%	6.15%	0.06%
General Motors Co	GM	0.19%	4.22%	0.01%	12.00%	0.02%
Microsoft Corp	MSFT	4.27%	1.35%	0.06%	11.62%	0.50%
Dollar General Corp	DG	0.15%	0.81%	0.00%	10.48%	0.02%
Cigna Corp	CI	0.28%	0.02%	0.00%	11.99%	0.03%
Kinder Morgan Inc/DE	KMI	0.16%	5.10%	0.01%	12.00%	0.02%
Citigroup Inc	C	0.61%	2.72%	0.02%	11.85%	0.07%
American International Group Inc	AIG	0.17%	2.43%	0.00%	11.00%	0.02%
Honeywell International Inc	HON	0.47%	2.02%	0.01%	7.64%	0.04%
Altria Group Inc	MO	0.34%	6.76%	0.02%	6.35%	0.02%
HCA Healthcare Inc	HCA	0.17%	1.15%	0.00%	10.25%	0.02%
Under Armour Inc	UAA	0.01%	n/a	n/a	31.94%	0.00%
International Paper Co	IP	0.07%	4.42%	0.00%	3.95%	0.00%
Hewlett Packard Enterprise Co	HPE	0.08%	3.03%	0.00%	5.41%	0.00%
Abbott Laboratories	ABT	0.56%	1.50%	0.01%	9.44%	0.05%
Aflac Inc	AFL	0.15%	1.97%	0.00%	3.41%	0.01%
Air Products & Chemicals Inc	APD	0.19%	1.96%	0.00%	10.64%	0.02%
Royal Caribbean Cruises Ltd	RCL	0.09%	2.60%	0.00%	10.06%	0.01%
American Electric Power Co Inc	AEP	0.17%	3.07%	0.01%	5.77%	0.01%
Hess Corp	HES	0.07%	1.61%	0.00%	-9.53%	-0.01%
Aon PLC	AON	0.18%	0.86%	0.00%	10.88%	0.02%
Apache Corp	APA	0.03%	4.49%	0.00%	-19.89%	-0.01%
Archer-Daniels-Midland Co	ADM	0.09%	3.26%	0.00%	-0.20%	0.00%
Automatic Data Processing Inc	ADP	0.27%	2.13%	0.01%	12.55%	0.03%
Verisk Analytics Inc	VRSK	0.09%	0.68%	0.00%	9.76%	0.01%
AutoZone Inc	AZO	0.10%	n/a	n/a	10.33%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Avery Dennison Corp	AVY	0.04%	1.78%	0.00%	4.90%	0.00%
MSCI Inc	MSCI	0.08%	1.05%	0.00%	12.87%	0.01%
Ball Corp	BLL	0.08%	0.91%	0.00%	5.50%	0.00%
Bank of New York Mellon Corp/The	BK	0.17%	2.53%	0.00%	6.83%	0.01%
Baxter International Inc	BAX	0.15%	1.07%	0.00%	12.00%	0.02%
Becton Dickinson and Co	BDX	0.26%	1.22%	0.00%	10.37%	0.03%
Berkshire Hathaway Inc	BRK/B	1.13%	n/a	n/a	n/a	n/a
Best Buy Co Inc	BBY	0.08%	2.48%	0.00%	7.52%	0.01%
H&R Block Inc	HRB	0.02%	4.27%	0.00%	10.00%	0.00%
Boston Scientific Corp	BSX	0.22%	n/a	n/a	8.88%	0.02%
Bristol-Myers Squibb Co	BMY	0.49%	2.88%	0.01%	15.20%	0.07%
Fortune Brands Home & Security Inc	FBHS	0.03%	1.39%	0.00%	8.51%	0.00%
Brown-Forman Corp	BF/B	0.08%	1.03%	0.00%	6.44%	0.00%
Cabot Oil & Gas Corp	COG	0.02%	2.51%	0.00%	28.01%	0.01%
Campbell Soup Co	CPB	0.05%	3.01%	0.00%	7.00%	0.00%
Kansas City Southern	KSU	0.06%	1.05%	0.00%	12.77%	0.01%
Hilton Worldwide Holdings Inc	HLT	0.11%	0.57%	0.00%	11.81%	0.01%
Carnival Corp	CCL	0.09%	4.44%	0.00%	7.59%	0.01%
Qorvo Inc	QRVO	0.04%	n/a	n/a	11.16%	0.00%
CenturyLink Inc	CTL	0.06%	6.90%	0.00%	3.97%	0.00%
UDR Inc	UDR	0.05%	2.85%	0.00%	6.67%	0.00%
Clorox Co/The	CLX	0.07%	2.86%	0.00%	3.56%	0.00%
CMS Energy Corp	CMS	0.06%	2.50%	0.00%	7.35%	0.00%
Newell Brands Inc	NWL	0.03%	4.79%	0.00%	-10.99%	0.00%
Colgate-Palmolive Co	CL	0.21%	2.54%	0.01%	3.60%	0.01%
Comerica Inc	CMA	0.04%	3.81%	0.00%	9.65%	0.00%
IPG Photonics Corp	IPGP	0.03%	n/a	n/a	-10.17%	0.00%
Conagra Brands Inc	CAG	0.05%	2.94%	0.00%	7.60%	0.00%
Consolidated Edison Inc	ED	0.11%	3.41%	0.00%	3.62%	0.00%
SL Green Realty Corp	SLG	0.03%	3.98%	0.00%	7.30%	0.00%
Corning Inc	GLW	0.08%	2.75%	0.00%	7.15%	0.01%
Cummins Inc	CMI	0.10%	2.87%	0.00%	10.00%	0.01%
Danaher Corp	DHR	0.39%	0.47%	0.00%	14.87%	0.06%
Target Corp	TGT	0.23%	2.11%	0.00%	8.95%	0.02%
Deere & Co	DE	0.20%	1.81%	0.00%	8.27%	0.02%
Dominion Energy Inc	D	0.25%	4.42%	0.01%	4.57%	0.01%
Dover Corp	DOV	0.06%	1.76%	0.00%	10.80%	0.01%
Alliant Energy Corp	LNT	0.05%	2.68%	0.00%	5.52%	0.00%
Duke Energy Corp	DUK	0.24%	4.29%	0.01%	4.98%	0.01%
Regency Centers Corp	REG	0.04%	3.60%	0.00%	4.85%	0.00%
Eaton Corp PLC	ETN	0.14%	3.07%	0.00%	8.62%	0.01%
Ecolab Inc	ECL	0.20%	0.99%	0.00%	13.07%	0.03%
PerkinElmer Inc	PKI	0.04%	0.30%	0.00%	16.97%	0.01%
Emerson Electric Co	EMR	0.17%	2.71%	0.00%	8.03%	0.01%
EOG Resources Inc	EOG	0.15%	1.62%	0.00%	5.25%	0.01%
Entergy Corp	ETR	0.09%	3.20%	0.00%	-1.04%	0.00%
Equifax Inc	EFX	0.06%	1.12%	0.00%	11.67%	0.01%
IQVIA Holdings Inc	IQV	0.10%	n/a	n/a	17.80%	0.02%
Gartner Inc	IT	0.05%	n/a	n/a	12.77%	0.01%
FedEx Corp	FDX	0.15%	1.62%	0.00%	19.52%	0.03%
Macy's Inc	M	0.02%	9.86%	0.00%	-0.83%	0.00%
FMC Corp	FMC	0.05%	1.63%	0.00%	9.50%	0.00%
Ford Motor Co	F	0.13%	6.62%	0.01%	3.06%	0.00%
NextEra Energy Inc	NEE	0.42%	2.14%	0.01%	8.12%	0.03%
Franklin Resources Inc	BEN	0.05%	3.78%	0.00%	10.00%	0.01%
Freeport-McMoRan Inc	FCX	0.06%	1.76%	0.00%	-1.93%	0.00%
Gap Inc/The	GPS	0.02%	5.84%	0.00%	5.03%	0.00%
General Dynamics Corp	GD	0.19%	2.25%	0.00%	8.28%	0.02%
General Mills Inc	GIS	0.12%	3.68%	0.00%	6.50%	0.01%
Genuine Parts Co	GPC	0.06%	2.92%	0.00%	4.48%	0.00%
Atmos Energy Corp	ATO	0.05%	2.15%	0.00%	6.67%	0.00%
WW Grainger Inc	GWW	0.06%	1.82%	0.00%	10.53%	0.01%
Halliburton Co	HAL	0.07%	3.43%	0.00%	4.40%	0.00%
Harley-Davidson Inc	HOG	0.02%	4.12%	0.00%	5.90%	0.00%
L3Harris Technologies Inc	LHX	0.16%	1.49%	0.00%	n/a	n/a
Healthpeak Properties Inc	PEAK	0.07%	4.24%	0.00%	2.96%	0.00%
Helmerich & Payne Inc	HP	0.02%	7.18%	0.00%	-4.23%	0.00%
Fortive Corp	FTV	0.09%	0.39%	0.00%	9.35%	0.01%
Hershey Co/The	HSY	0.08%	2.09%	0.00%	7.90%	0.01%
Synchrony Financial	SYF	0.09%	2.35%	0.00%	5.57%	0.00%
Hormel Foods Corp	HRL	0.09%	2.09%	0.00%	3.82%	0.00%
Arthur J Gallagher & Co	AJG	0.06%	1.84%	0.00%	9.83%	0.01%
Mondelez International Inc	MDLZ	0.28%	2.17%	0.01%	7.81%	0.02%
CenterPoint Energy Inc	CNP	0.05%	4.68%	0.00%	4.22%	0.00%
Humana Inc	HUM	0.17%	0.64%	0.00%	13.38%	0.02%
Willis Towers Watson PLC	WLTW	0.09%	1.32%	0.00%	10.00%	0.01%
Illinois Tool Works Inc	ITW	0.21%	2.46%	0.01%	6.87%	0.01%
CDW Corp/DE	CDW	0.07%	1.13%	0.00%	13.55%	0.01%
Ingersoll-Rand PLC	IR	0.12%	1.62%	0.00%	9.84%	0.01%
Interpublic Group of Cos Inc/The	IPG	0.03%	4.20%	0.00%	10.28%	0.00%
International Flavors & Fragrances Inc	IFF	0.06%	2.12%	0.00%	9.57%	0.01%
Jacobs Engineering Group Inc	JEC	0.05%	0.74%	0.00%	11.99%	0.01%

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Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Hanesbrands Inc	HBI	0.02%	3.98%	0.00%	5.54%	0.00%
Kellogg Co	K	0.08%	3.50%	0.00%	1.55%	0.00%
Broadridge Financial Solutions Inc	BR	0.05%	1.75%	0.00%	n/a	n/a
Perrigo Co PLC	PRGO	0.03%	1.64%	0.00%	-1.60%	0.00%
Kimberly-Clark Corp	KMB	0.17%	3.02%	0.01%	4.43%	0.01%
Kimco Realty Corp	KIM	0.03%	5.18%	0.00%	4.17%	0.00%
Kohl's Corp	KSS	0.03%	5.70%	0.00%	6.17%	0.00%
Oracle Corp	ORCL	0.68%	1.71%	0.01%	8.38%	0.06%
Kroger Co/The	KR	0.08%	2.34%	0.00%	4.45%	0.00%
Leggett & Platt Inc	LEG	0.03%	3.06%	0.00%	n/a	n/a
Lennar Corp	LEN	0.06%	0.27%	0.00%	10.52%	0.01%
Eli Lilly & Co	LLY	0.42%	2.20%	0.01%	10.21%	0.04%
L Brands Inc	LB	0.02%	6.27%	0.00%	11.50%	0.00%
Charter Communications Inc	CHTR	0.37%	n/a	n/a	35.10%	0.13%
Lincoln National Corp	LNC	0.04%	2.71%	0.00%	9.00%	0.00%
Loews Corp	L	0.06%	0.49%	0.00%	n/a	n/a
Lowe's Cos Inc	LOW	0.33%	1.88%	0.01%	15.70%	0.05%
Host Hotels & Resorts Inc	HST	0.05%	4.57%	0.00%	18.86%	0.01%
Xerox Holdings Corp	XRX	0.03%	2.57%	0.00%	5.90%	0.00%
IDEX Corp	IEX	0.05%	1.23%	0.00%	10.63%	0.00%
Marsh & McLennan Cos Inc	MMC	0.20%	1.68%	0.00%	10.65%	0.02%
Masco Corp	MAS	0.05%	1.16%	0.00%	9.68%	0.00%
S&P Global Inc	SPGI	0.24%	0.86%	0.00%	10.47%	0.03%
Medtronic PLC	MDT	0.55%	1.94%	0.01%	7.66%	0.04%
CVS Health Corp	CVS	0.36%	2.66%	0.01%	6.23%	0.02%
DuPont de Nemours Inc	DD	0.18%	1.85%	0.00%	5.14%	0.01%
Micron Technology Inc	MU	0.19%	n/a	n/a	-0.32%	0.00%
Motorola Solutions Inc	MSI	0.11%	1.53%	0.00%	7.10%	0.01%
Cboe Global Markets Inc	CBOE	0.05%	1.21%	0.00%	7.15%	0.00%
Mylan NV	MYL	0.04%	n/a	n/a	-5.67%	0.00%
Laboratory Corp of America Holdings	LH	0.06%	n/a	n/a	9.51%	0.01%
Newmont Goldcorp Corp	NEM	0.12%	1.46%	0.00%	3.65%	0.00%
NIKE Inc	NKE	0.43%	1.05%	0.00%	13.95%	0.06%
NiSource Inc	NI	0.04%	3.02%	0.00%	4.81%	0.00%
Noble Energy Inc	NBL	0.04%	2.31%	0.00%	11.69%	0.00%
Norfolk Southern Corp	NSC	0.19%	1.94%	0.00%	12.74%	0.02%
Principal Financial Group Inc	PFG	0.06%	3.99%	0.00%	5.26%	0.00%
Eversource Energy	ES	0.10%	2.59%	0.00%	6.34%	0.01%
Northrop Grumman Corp	NOC	0.22%	1.50%	0.00%	7.34%	0.02%
Wells Fargo & Co	WFC	0.85%	3.75%	0.03%	9.56%	0.08%
Nucor Corp	NUE	0.06%	2.84%	0.00%	0.40%	0.00%
PVH Corp	PVH	0.03%	0.15%	0.00%	6.30%	0.00%
Occidental Petroleum Corp	OXY	0.13%	8.19%	0.01%	5.00%	0.01%
Omnicom Group Inc	OMC	0.06%	3.27%	0.00%	4.10%	0.00%
ONEOK Inc	OKE	0.11%	5.15%	0.01%	11.02%	0.01%
Raymond James Financial Inc	RJF	0.05%	1.65%	0.00%	11.10%	0.01%
Parker-Hannifin Corp	PH	0.09%	1.77%	0.00%	9.85%	0.01%
Rollins Inc	ROL	0.04%	1.17%	0.00%	n/a	n/a
PPL Corp	PPL	0.09%	4.85%	0.00%	1.18%	0.00%
ConocoPhillips	COP	0.24%	2.80%	0.01%	0.80%	0.00%
PulteGroup Inc	PHM	0.04%	1.11%	0.00%	9.30%	0.00%
Pinnacle West Capital Corp	PNW	0.04%	3.58%	0.00%	5.09%	0.00%
PNC Financial Services Group Inc/The	PNC	0.25%	3.00%	0.01%	7.14%	0.02%
PPG Industries Inc	PPG	0.11%	1.58%	0.00%	6.29%	0.01%
Progressive Corp/The	PGR	0.16%	0.55%	0.00%	6.23%	0.01%
Public Service Enterprise Group Inc	PEG	0.11%	3.17%	0.00%	5.25%	0.01%
Raytheon Co	RTN	0.22%	1.73%	0.00%	8.68%	0.02%
Robert Half International Inc	RHI	0.02%	2.13%	0.00%	-2.17%	0.00%
Edison International	EIX	0.09%	3.55%	0.00%	5.06%	0.00%
Schlumberger Ltd	SLB	0.19%	5.52%	0.01%	27.22%	0.05%
Charles Schwab Corp/The	SCHW	0.23%	1.37%	0.00%	3.49%	0.01%
Sherwin-Williams Co/The	SHW	0.20%	0.78%	0.00%	11.24%	0.02%
JM Smucker Co/The	SJM	0.04%	3.35%	0.00%	1.99%	0.00%
Snap-on Inc	SNA	0.03%	2.69%	0.00%	6.74%	0.00%
AMETEK Inc	AME	0.08%	0.57%	0.00%	9.59%	0.01%
Southern Co/The	SO	0.24%	4.00%	0.01%	3.98%	0.01%
BB&T Corp	BBT	0.15%	3.29%	0.01%	5.67%	0.01%
Southwest Airlines Co	LUV	0.11%	1.25%	0.00%	7.55%	0.01%
Stanley Black & Decker Inc	SWK	0.09%	1.75%	0.00%	8.77%	0.01%
Public Storage	PSA	0.14%	3.80%	0.01%	3.52%	0.00%
Arista Networks Inc	ANET	0.06%	n/a	n/a	18.60%	0.01%
SunTrust Banks Inc	STI	0.12%	3.16%	0.00%	1.21%	0.00%
Sysco Corp	SYY	0.15%	2.23%	0.00%	10.77%	0.02%
Corteva Inc	CTVA	0.07%	2.00%	0.00%	15.60%	0.01%
Texas Instruments Inc	TXN	0.42%	2.99%	0.01%	8.23%	0.03%
Textron Inc	TXT	0.04%	0.17%	0.00%	10.29%	0.00%
Thermo Fisher Scientific Inc	TMO	0.47%	0.24%	0.00%	11.70%	0.05%
Tiffany & Co	TIF	0.06%	1.73%	0.00%	8.68%	0.01%
TJX Cos Inc/The	TJX	0.27%	1.51%	0.00%	11.07%	0.03%
Globe Life Inc	GL	0.04%	0.67%	0.00%	8.07%	0.00%
Johnson Controls International plc	JCI	0.12%	2.43%	0.00%	9.67%	0.01%
Ulta Beauty Inc	ULTA	0.05%	n/a	n/a	17.30%	0.01%

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Union Pacific Corp	UNP	0.45%	2.20%	0.01%	12.83%	0.06%
Keysight Technologies Inc	KEYS	0.07%	n/a	n/a	18.20%	0.01%
UnitedHealth Group Inc	UNH	0.98%	1.54%	0.02%	14.56%	0.14%
Unum Group	UNM	0.02%	3.71%	0.00%	9.00%	0.00%
Marathon Oil Corp	MRO	0.03%	1.72%	0.00%	5.00%	0.00%
Varian Medical Systems Inc	VAR	0.04%	n/a	n/a	11.95%	0.01%
Ventas Inc	VTR	0.08%	5.44%	0.00%	4.23%	0.00%
VF Corp	VFC	0.13%	2.17%	0.00%	9.93%	0.01%
Vornado Realty Trust	VNO	0.05%	4.09%	0.00%	5.15%	0.00%
Vulcan Materials Co	VMC	0.07%	0.87%	0.00%	19.05%	0.01%
Weyerhaeuser Co	WY	0.08%	4.61%	0.00%	3.80%	0.00%
Whirlpool Corp	WHR	0.03%	3.35%	0.00%	4.07%	0.00%
Williams Cos Inc/The	WMB	0.10%	6.69%	0.01%	6.50%	0.01%
WEC Energy Group Inc	WEC	0.10%	2.66%	0.00%	6.66%	0.01%
Adobe Inc	ADBE	0.55%	n/a	n/a	16.00%	0.09%
AES Corp/VA	AES	0.05%	2.89%	0.00%	8.35%	0.00%
Amgen Inc	AMGN	0.52%	2.47%	0.01%	8.16%	0.04%
Apple Inc	AAPL	4.39%	1.15%	0.05%	11.23%	0.49%
Autodesk Inc	ADSK	0.15%	n/a	n/a	47.95%	0.07%
Cintas Corp	CTAS	0.10%	0.99%	0.00%	11.07%	0.01%
Comcast Corp	CMCSA	0.74%	1.90%	0.01%	11.28%	0.08%
Molson Coors Brewing Co	TAP	0.04%	4.52%	0.00%	-3.45%	0.00%
KLA Corp	KLAC	0.10%	2.07%	0.00%	13.90%	0.01%
Marriott International Inc/MD	MAR	0.17%	1.37%	0.00%	7.84%	0.01%
McCormick & Co Inc/MD	MKC	0.08%	1.47%	0.00%	6.20%	0.00%
Nordstrom Inc	JWN	0.02%	3.88%	0.00%	5.83%	0.00%
PACCAR Inc	PCAR	0.10%	1.57%	0.00%	5.03%	0.01%
Costco Wholesale Corp	COST	0.49%	0.87%	0.00%	8.43%	0.04%
First Republic Bank/CA	FRC	0.07%	0.69%	0.00%	9.43%	0.01%
Stryker Corp	SYK	0.28%	1.02%	0.00%	9.38%	0.03%
Tyson Foods Inc	TSN	0.10%	1.87%	0.00%	7.28%	0.01%
Lamb Weston Holdings Inc	LW	0.05%	0.95%	0.00%	7.99%	0.00%
Applied Materials Inc	AMAT	0.20%	1.45%	0.00%	12.42%	0.02%
American Airlines Group Inc	AAL	0.05%	1.39%	0.00%	4.73%	0.00%
Cardinal Health Inc	CAH	0.06%	3.50%	0.00%	1.37%	0.00%
Cerner Corp	CERN	0.08%	1.01%	0.00%	15.45%	0.01%
Cincinnati Financial Corp	CINF	0.06%	2.09%	0.00%	n/a	n/a
DR Horton Inc	DHI	0.08%	1.26%	0.00%	16.29%	0.01%
Flowserve Corp	FLS	0.02%	1.56%	0.00%	14.51%	0.00%
Electronic Arts Inc	EA	0.11%	n/a	n/a	-0.86%	0.00%
Expeditors International of Washington Inc	EXPD	0.05%	1.34%	0.00%	9.73%	0.00%
Fastenal Co	FAST	0.08%	2.48%	0.00%	7.10%	0.01%
M&T Bank Corp	MTB	0.08%	2.67%	0.00%	4.31%	0.00%
Xcel Energy Inc	XEL	0.12%	2.63%	0.00%	5.61%	0.01%
Fiserv Inc	FISV	0.29%	n/a	n/a	12.00%	0.04%
Fifth Third Bancorp	FITB	0.08%	3.18%	0.00%	5.05%	0.00%
Gilead Sciences Inc	GILD	0.31%	3.75%	0.01%	8.89%	0.03%
Hasbro Inc	HAS	0.05%	2.67%	0.00%	9.40%	0.00%
Huntington Bancshares Inc/OH	HBAN	0.06%	4.03%	0.00%	5.24%	0.00%
Welltower Inc	WELL	0.13%	4.11%	0.01%	3.47%	0.00%
Biogen Inc	BIIB	0.20%	n/a	n/a	2.90%	0.01%
Northern Trust Corp	NTRS	0.08%	2.61%	0.00%	8.36%	0.01%
Packaging Corp of America	PKG	0.04%	2.82%	0.00%	10.00%	0.00%
Paychex Inc	PAYX	0.11%	2.88%	0.00%	7.00%	0.01%
People's United Financial Inc	PBCT	0.03%	4.30%	0.00%	2.00%	0.00%
QUALCOMM Inc	QCOM	0.35%	2.97%	0.01%	12.25%	0.04%
Roper Technologies Inc	ROP	0.14%	0.57%	0.00%	12.77%	0.02%
Ross Stores Inc	ROST	0.16%	0.88%	0.00%	9.80%	0.02%
IDEXX Laboratories Inc	IDXX	0.08%	n/a	n/a	18.53%	0.01%
Starbucks Corp	SBUX	0.37%	1.92%	0.01%	13.17%	0.05%
KeyCorp	KEY	0.07%	3.82%	0.00%	4.89%	0.00%
Fox Corp	FOXA	0.05%	1.29%	0.00%	6.40%	0.00%
Fox Corp	FOX	0.03%	1.32%	0.00%	-2.46%	0.00%
State Street Corp	STT	0.10%	2.77%	0.00%	7.41%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	0.04%	n/a	n/a	8.21%	0.00%
US Bancorp	USB	0.35%	2.80%	0.01%	6.40%	0.02%
AO Smith Corp	AOS	0.02%	1.98%	0.00%	8.00%	0.00%
NortonLifeLock Inc	NLOK	0.06%	2.01%	0.00%	4.67%	0.00%
T Rowe Price Group Inc	TROW	0.11%	2.46%	0.00%	7.66%	0.01%
Waste Management Inc	WM	0.18%	1.82%	0.00%	7.50%	0.01%
CBS Corp	CBS	0.05%	1.78%	0.00%	9.98%	0.01%
Allergan PLC	AGN	0.22%	1.60%	0.00%	8.00%	0.02%
Constellation Brands Inc	STZ	0.12%	1.61%	0.00%	5.73%	0.01%
Xilinx Inc	XLNX	0.09%	1.60%	0.00%	9.05%	0.01%
DENTSPLY SIRONA Inc	XRAY	0.05%	0.71%	0.00%	13.27%	0.01%
Zions Bancorp NA	ZION	0.03%	2.73%	0.00%	3.64%	0.00%
Alaska Air Group Inc	ALK	0.03%	2.03%	0.00%	19.55%	0.01%
Invesco Ltd	IVZ	0.03%	7.06%	0.00%	5.37%	0.00%
Linde PLC	LIN	0.41%	1.70%	0.01%	9.50%	0.04%
Intuit Inc	INTU	0.25%	0.82%	0.00%	13.66%	0.03%
Morgan Stanley	MS	0.30%	2.83%	0.01%	10.54%	0.03%
Microchip Technology Inc	MCHP	0.08%	1.55%	0.00%	6.17%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Chubb Ltd	CB	0.25%	1.98%	0.01%	10.73%	0.03%
Hologic Inc	HOLX	0.05%	n/a	n/a	9.29%	0.00%
Citizens Financial Group Inc	CFG	0.06%	3.74%	0.00%	5.50%	0.00%
O'Reilly Automotive Inc	ORLY	0.12%	n/a	n/a	11.92%	0.01%
Allstate Corp/The	ALL	0.13%	1.80%	0.00%	9.00%	0.01%
FLIR Systems Inc	FLIR	0.03%	1.27%	0.00%	13.10%	0.00%
Equity Residential	EQR	0.12%	2.67%	0.00%	8.77%	0.01%
BorgWarner Inc	BWA	0.03%	1.62%	0.00%	-1.52%	0.00%
Incyte Corp	INCY	0.07%	n/a	n/a	32.00%	0.02%
Simon Property Group Inc	SPG	0.17%	5.56%	0.01%	3.63%	0.01%
Eastman Chemical Co	EMN	0.04%	3.16%	0.00%	5.30%	0.00%
Twitter Inc	TWTR	0.09%	n/a	n/a	25.40%	0.02%
AvalonBay Communities Inc	AVB	0.11%	2.84%	0.00%	7.17%	0.01%
Prudential Financial Inc	PRU	0.14%	4.27%	0.01%	9.00%	0.01%
United Parcel Service Inc	UPS	0.31%	3.21%	0.01%	8.48%	0.03%
Apartment Investment & Management Co	AIV	0.03%	2.90%	0.00%	3.45%	0.00%
Walgreens Boots Alliance Inc	WBA	0.20%	3.07%	0.01%	5.31%	0.01%
McKesson Corp	MCK	0.10%	1.13%	0.00%	6.96%	0.01%
Lockheed Martin Corp	LMT	0.41%	2.46%	0.01%	9.36%	0.04%
AmerisourceBergen Corp	ABC	0.07%	1.82%	0.00%	4.18%	0.00%
Capital One Financial Corp	COF	0.17%	1.60%	0.00%	4.97%	0.01%
Waters Corp	WAT	0.05%	n/a	n/a	10.84%	0.01%
Dollar Tree Inc	DLTR	0.08%	n/a	n/a	6.87%	0.01%
Darden Restaurants Inc	DRI	0.05%	2.97%	0.00%	8.78%	0.00%
NVR Inc	NVR	0.05%	n/a	n/a	11.81%	0.01%
NetApp Inc	NTAP	0.05%	3.17%	0.00%	5.54%	0.00%
Citrix Systems Inc	CTXS	0.05%	1.24%	0.00%	7.80%	0.00%
DXC Technology Co	DXC	0.04%	2.25%	0.00%	-1.02%	0.00%
DaVita Inc	DVA	0.03%	n/a	n/a	17.12%	0.01%
Hartford Financial Services Group Inc/The	HIG	0.08%	1.94%	0.00%	9.50%	0.01%
Iron Mountain Inc	IRM	0.03%	7.70%	0.00%	4.42%	0.00%
Estee Lauder Cos Inc/The	EL	0.16%	0.98%	0.00%	12.72%	0.02%
Cadence Design Systems Inc	CDNS	0.07%	n/a	n/a	9.35%	0.01%
Universal Health Services Inc	UHS	0.04%	0.57%	0.00%	6.15%	0.00%
E*TRADE Financial Corp	ETFC	0.04%	1.26%	0.00%	-0.29%	0.00%
Skyworks Solutions Inc	SWKS	0.06%	1.79%	0.00%	16.29%	0.01%
National Oilwell Varco Inc	NOV	0.03%	0.89%	0.00%	54.53%	0.02%
Quest Diagnostics Inc	DGX	0.05%	1.99%	0.00%	4.62%	0.00%
Activision Blizzard Inc	ATVI	0.16%	0.67%	0.00%	13.37%	0.02%
Rockwell Automation Inc	ROK	0.08%	2.08%	0.00%	7.97%	0.01%
Kraft Heinz Co/The	KHC	0.14%	5.25%	0.01%	-1.87%	0.00%
American Tower Corp	AMT	0.35%	1.78%	0.01%	20.71%	0.07%
HollyFrontier Corp	HFC	0.03%	2.72%	0.00%	-5.47%	0.00%
Regeneron Pharmaceuticals Inc	REGN	0.15%	n/a	n/a	9.59%	0.01%
Amazon.com Inc	AMZN	3.30%	n/a	n/a	33.98%	1.12%
Jack Henry & Associates Inc	JKHY	0.04%	1.05%	0.00%	12.10%	0.01%
Ralph Lauren Corp	RL	0.02%	2.56%	0.00%	5.08%	0.00%
Boston Properties Inc	BXP	0.08%	2.74%	0.00%	2.44%	0.00%
Amphenol Corp	APH	0.11%	0.96%	0.00%	8.41%	0.01%
Arconic Inc	ARNC	0.05%	0.26%	0.00%	11.20%	0.01%
Pioneer Natural Resources Co	PXD	0.08%	1.38%	0.00%	23.88%	0.02%
Valero Energy Corp	VLO	0.14%	3.77%	0.01%	15.00%	0.02%
Synopsys Inc	SNPS	0.08%	n/a	n/a	14.38%	0.01%
Western Union Co/The	WU	0.04%	2.98%	0.00%	4.20%	0.00%
CH Robinson Worldwide Inc	CHRW	0.04%	2.60%	0.00%	10.00%	0.00%
Accenture PLC	ACN	0.47%	1.59%	0.01%	10.10%	0.05%
TransDigm Group Inc	TDG	0.11%	n/a	n/a	13.16%	0.01%
Yum! Brands Inc	YUM	0.11%	1.67%	0.00%	11.75%	0.01%
Prologis Inc	PLD	0.21%	2.32%	0.00%	7.55%	0.02%
FirstEnergy Corp	FE	0.10%	3.27%	0.00%	0.56%	0.00%
VeriSign Inc	VRSN	0.08%	n/a	n/a	10.30%	0.01%
Quanta Services Inc	PWR	0.02%	0.38%	0.00%	14.50%	0.00%
Henry Schein Inc	HSIC	0.04%	n/a	n/a	3.52%	0.00%
Ameren Corp	AEE	0.07%	2.66%	0.00%	5.32%	0.00%
ANSYS Inc	ANSS	0.08%	n/a	n/a	12.77%	0.01%
NVIDIA Corp	NVDA	0.49%	0.30%	0.00%	9.37%	0.05%
Sealed Air Corp	SEE	0.02%	1.70%	0.00%	5.08%	0.00%
Cognizant Technology Solutions Corp	CTSH	0.13%	1.25%	0.00%	11.20%	0.01%
SVB Financial Group	SIVB	0.04%	n/a	n/a	11.00%	0.00%
Intuitive Surgical Inc	ISRG	0.25%	n/a	n/a	13.24%	0.03%
Affiliated Managers Group Inc	AMG	0.02%	1.50%	0.00%	5.60%	0.00%
Take-Two Interactive Software Inc	TTWO	0.05%	n/a	n/a	7.93%	0.00%
Republic Services Inc	RSG	0.10%	1.83%	0.00%	8.38%	0.01%
eBay Inc	EBAY	0.11%	1.58%	0.00%	12.25%	0.01%
Goldman Sachs Group Inc/The	GS	0.29%	2.26%	0.01%	1.84%	0.01%
SBA Communications Corp	SBAC	0.10%	0.63%	0.00%	28.40%	0.03%
Sempra Energy	SRE	0.15%	2.63%	0.00%	9.40%	0.01%
Moody's Corp	MCO	0.16%	0.88%	0.00%	9.73%	0.02%
Booking Holdings Inc	BKNG	0.29%	n/a	n/a	16.02%	0.05%
F5 Networks Inc	FFIV	0.03%	n/a	n/a	8.34%	0.00%
Akamai Technologies Inc	AKAM	0.05%	n/a	n/a	12.80%	0.01%
MarketAxess Holdings Inc	MKTX	0.06%	0.51%	0.00%	n/a	n/a

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Devon Energy Corp	DVN	0.03%	1.64%	0.00%	9.93%	0.00%
Alphabet Inc	GOOGL	1.44%	n/a	n/a	13.16%	0.19%
Teleflex Inc	TFX	0.06%	0.38%	0.00%	15.00%	0.01%
Allegion PLC	ALLE	0.04%	0.90%	0.00%	10.46%	0.00%
Netflix Inc	NFLX	0.51%	n/a	n/a	30.53%	0.16%
Agilent Technologies Inc	A	0.09%	0.89%	0.00%	13.20%	0.01%
Anthem Inc	ANTM	0.27%	1.11%	0.00%	14.40%	0.04%
CME Group Inc	CME	0.27%	1.48%	0.00%	8.67%	0.02%
Juniper Networks Inc	JNPR	0.03%	3.03%	0.00%	7.36%	0.00%
BlackRock Inc	BLK	0.28%	2.67%	0.01%	9.11%	0.03%
DTE Energy Co	DTE	0.09%	3.24%	0.00%	5.73%	0.01%
Celanese Corp	CE	0.06%	1.98%	0.00%	4.96%	0.00%
Nasdaq Inc	NDAQ	0.06%	1.79%	0.00%	13.85%	0.01%
Philip Morris International Inc	PM	0.48%	5.64%	0.03%	6.50%	0.03%
salesforce.com Inc	CRM	0.53%	n/a	n/a	22.54%	0.12%
Huntington Ingalls Industries Inc	HII	0.04%	1.64%	0.00%	40.00%	0.02%
MetLife Inc	MET	0.17%	3.53%	0.01%	9.42%	0.02%
Under Armour Inc	UA	0.01%	n/a	n/a	28.88%	0.00%
Tapestry Inc	TPR	0.03%	5.02%	0.00%	8.23%	0.00%
CSX Corp	CSX	0.21%	1.34%	0.00%	12.12%	0.03%
Edwards Lifesciences Corp	EW	0.19%	n/a	n/a	16.00%	0.03%
Ameriprise Financial Inc	AMP	0.08%	2.37%	0.00%	6.00%	0.00%
TechnipFMC PLC	FTI	0.03%	2.76%	0.00%	18.55%	0.01%
Zimmer Biomet Holdings Inc	ZBH	0.11%	0.66%	0.00%	6.38%	0.01%
CBRE Group Inc	CBRE	0.07%	n/a	n/a	11.00%	0.01%
Mastercard Inc	MA	1.08%	0.45%	0.00%	17.46%	0.19%
CarMax Inc	KMX	0.06%	n/a	n/a	10.68%	0.01%
Intercontinental Exchange Inc	ICE	0.19%	1.17%	0.00%	9.80%	0.02%
Fidelity National Information Services Inc	FIS	0.31%	1.01%	0.00%	11.94%	0.04%
Chipotle Mexican Grill Inc	CMG	0.08%	n/a	n/a	23.12%	0.02%
Wynn Resorts Ltd	WYNN	0.05%	3.31%	0.00%	13.10%	0.01%
Assurant Inc	AIZ	0.03%	1.90%	0.00%	n/a	n/a
NRG Energy Inc	NRG	0.04%	0.30%	0.00%	39.35%	0.01%
Monster Beverage Corp	MNST	0.12%	n/a	n/a	12.50%	0.01%
Regions Financial Corp	RF	0.06%	3.73%	0.00%	8.48%	0.01%
Mosaic Co/The	MOS	0.03%	1.05%	0.00%	4.95%	0.00%
Expedia Group Inc	EXPE	0.05%	1.34%	0.00%	12.35%	0.01%
Evergy Inc	EVRG	0.05%	3.19%	0.00%	6.57%	0.00%
Discovery Inc	DISCA	0.02%	n/a	n/a	13.70%	0.00%
CF Industries Holdings Inc	CF	0.04%	2.60%	0.00%	19.47%	0.01%
Viacom Inc	VIAB	0.03%	3.32%	0.00%	-1.07%	0.00%
Leidos Holdings Inc	LDOS	0.05%	1.50%	0.00%	10.00%	0.00%
Alphabet Inc	GOOG	1.66%	n/a	n/a	13.16%	0.22%
TE Connectivity Ltd	TEL	0.11%	1.98%	0.00%	9.98%	0.01%
Cooper Cos Inc/The	COO	0.06%	0.02%	0.00%	6.03%	0.00%
Discover Financial Services	DFS	0.10%	2.07%	0.00%	7.19%	0.01%
TripAdvisor Inc	TRIP	0.01%	n/a	n/a	10.04%	0.00%
Visa Inc	V	1.17%	0.65%	0.01%	15.54%	0.18%
Mid-America Apartment Communities Inc	MAA	0.06%	2.82%	0.00%	n/a	n/a
Xylem Inc/NY	XYL	0.05%	1.24%	0.00%	13.03%	0.01%
Marathon Petroleum Corp	MPC	0.15%	3.50%	0.01%	12.05%	0.02%
Advanced Micro Devices Inc	AMD	0.16%	n/a	n/a	23.90%	0.04%
Tractor Supply Co	TSCO	0.04%	1.48%	0.00%	10.83%	0.00%
ResMed Inc	RMD	0.08%	1.04%	0.00%	14.40%	0.01%
Mettler-Toledo International Inc	MTD	0.06%	n/a	n/a	13.25%	0.01%
Copart Inc	CPRT	0.08%	n/a	n/a	n/a	n/a
Fortinet Inc	FTNT	0.07%	n/a	n/a	16.66%	0.01%
Albemarle Corp	ALB	0.03%	2.25%	0.00%	7.66%	0.00%
Essex Property Trust Inc	ESS	0.08%	2.50%	0.00%	8.22%	0.01%
Realty Income Corp	O	0.09%	3.55%	0.00%	5.31%	0.00%
Seagate Technology PLC	STX	0.06%	4.36%	0.00%	5.37%	0.00%
Westrock Co	WRK	0.04%	4.61%	0.00%	2.50%	0.00%
IHS Markit Ltd	INFO	0.11%	n/a	n/a	12.00%	0.01%
Westinghouse Air Brake Technologies Corp	WAB	0.06%	0.61%	0.00%	11.42%	0.01%
Western Digital Corp	WDC	0.06%	3.97%	0.00%	3.50%	0.00%
PepsiCo Inc	PEP	0.70%	2.81%	0.02%	5.08%	0.04%
Diamondback Energy Inc	FANG	0.05%	0.97%	0.00%	20.29%	0.01%
Maxim Integrated Products Inc	MXIM	0.06%	3.39%	0.00%	6.78%	0.00%
ServiceNow Inc	NOW	0.20%	n/a	n/a	34.20%	0.07%
Church & Dwight Co Inc	CHD	0.06%	1.30%	0.00%	8.29%	0.01%
Duke Realty Corp	DRE	0.05%	2.67%	0.00%	4.74%	0.00%
Federal Realty Investment Trust	FRT	0.04%	3.18%	0.00%	5.71%	0.00%
MGM Resorts International	MGM	0.06%	1.63%	0.00%	5.08%	0.00%
JB Hunt Transport Services Inc	JBHT	0.05%	0.90%	0.00%	11.93%	0.01%
Lam Research Corp	LRCX	0.14%	1.72%	0.00%	15.89%	0.02%
Mohawk Industries Inc	MHK	0.04%	n/a	n/a	4.99%	0.00%
Pentair PLC	PNR	0.03%	1.62%	0.00%	6.20%	0.00%
Vertex Pharmaceuticals Inc	VRTX	0.21%	n/a	n/a	31.04%	0.07%
Amcor PLC	AMCR	0.06%	4.48%	0.00%	6.30%	0.00%
Facebook Inc	FB	1.79%	n/a	n/a	19.49%	0.35%
T-Mobile US Inc	TMUS	0.25%	n/a	n/a	7.55%	0.02%
United Rentals Inc	URI	0.04%	n/a	n/a	10.80%	0.00%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Alexandria Real Estate Equities Inc	ARE	0.07%	2.46%	0.00%	5.14%	0.00%
ABIOMED Inc	ABMD	0.03%	n/a	n/a	24.00%	0.01%
Delta Air Lines Inc	DAL	0.14%	2.81%	0.00%	11.87%	0.02%
United Airlines Holdings Inc	UAL	0.09%	n/a	n/a	10.91%	0.01%
News Corp	NWS	0.01%	1.52%	0.00%	-2.38%	0.00%
Centene Corp	CNC	0.09%	n/a	n/a	14.90%	0.01%
Macerich Co/The	MAC	0.01%	11.14%	0.00%	-0.88%	0.00%
Martin Marietta Materials Inc	MLM	0.06%	0.82%	0.00%	16.02%	0.01%
PayPal Holdings Inc	PYPL	0.47%	n/a	n/a	18.72%	0.09%
Coty Inc	COTY	0.03%	4.33%	0.00%	7.31%	0.00%
DISH Network Corp	DISH	0.03%	n/a	n/a	5.40%	0.00%
Alexion Pharmaceuticals Inc	ALXN	0.09%	n/a	n/a	12.60%	0.01%
Dow Inc	DOW	0.15%	5.25%	0.01%	-0.71%	0.00%
Everest Re Group Ltd	RE	0.04%	2.29%	0.00%	10.00%	0.00%
WellCare Health Plans Inc	WCG	0.06%	n/a	n/a	19.87%	0.01%
News Corp	NWSA	0.02%	1.55%	0.00%	-2.38%	0.00%
Exelon Corp	EXC	0.16%	3.27%	0.01%	2.86%	0.00%
Global Payments Inc	GPN	0.20%	0.43%	0.00%	18.50%	0.04%
Crown Castle International Corp	CCI	0.21%	3.59%	0.01%	17.07%	0.04%
Aptiv PLC	APTV	0.09%	0.94%	0.00%	5.97%	0.01%
Advance Auto Parts Inc	AAP	0.04%	0.15%	0.00%	15.34%	0.01%
Capri Holdings Ltd	CPRI	0.02%	n/a	n/a	4.07%	0.00%
Align Technology Inc	ALGN	0.08%	n/a	n/a	20.26%	0.02%
Illumina Inc	ILMN	0.17%	n/a	n/a	22.26%	0.04%
Alliance Data Systems Corp	ADS	0.02%	2.36%	0.00%	12.07%	0.00%
LKQ Corp	LKQ	0.04%	n/a	n/a	13.50%	0.01%
Nielsen Holdings PLC	NLSN	0.03%	1.23%	0.00%	7.55%	0.00%
Garmin Ltd	GRMN	0.07%	2.33%	0.00%	6.96%	0.00%
Cimarex Energy Co	XEC	0.02%	1.74%	0.00%	16.48%	0.00%
Zoetis Inc	ZTS	0.21%	0.54%	0.00%	11.47%	0.02%
Digital Realty Trust Inc	DLR	0.09%	3.57%	0.00%	41.20%	0.04%
Equinix Inc	EQIX	0.18%	1.74%	0.00%	18.00%	0.03%
Las Vegas Sands Corp	LVS	0.18%	4.91%	0.01%	4.16%	0.01%
Discovery Inc	DISCK	0.04%	n/a	n/a	13.70%	0.01%

Notes:
[7] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report, November 29, 2019
[8] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report, November 29, 2019
[9] Equals ([7] x (1 + (0.5 x [8]))) + [8]
[10] Equals sum of Col. [15]
[11] Equals sum of Col. [17]
[12] Equals ([10] x (1 + (0.5 x [11]))) + [11]
[13] Equals weight in S&P 500 based on market capitalization
[14] Source: Bloomberg Professional, as of November 29, 2019.
[15] Equals [13] x [14]
[16] Source: Bloomberg Professional, as of November 29, 2019.
[17] Equals [13] x [16]

Docket No. UE 374
Exhibit PAC/409
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Risk Premium Approach

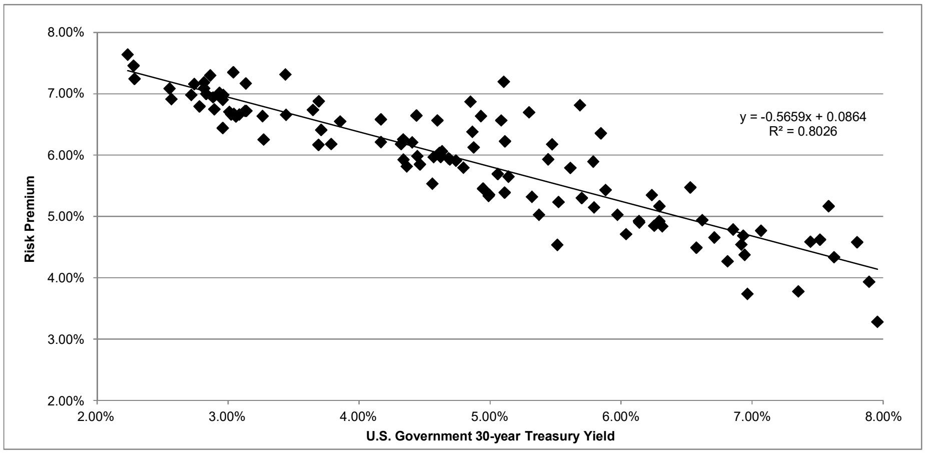
February 2020

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Electric ROE	U.S. Govt. 30-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%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2012.2	9.95%	2.93%	7.02%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.17%
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	9.87%	2.23%	7.64%
AVERAGE	10.72%	4.80%	5.92%
MEDIAN	10.63%	4.77%	6.05%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.89586
R Square	0.80256
Adjusted R Square	0.80077
Standard Error	0.00432
Observations	112

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.008334	0.008334	447.131172	0.000000
Residual	110	0.002050	0.000019		
Total	111	0.010385			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0864	0.00135	64.11	0.000000	0.083734	0.089076	0.083734	0.089076
U.S. Govt. 30-year Treasury	(0.5659)	0.02676	(21.15)	0.000000	(0.618921)	(0.512851)	(0.618921)	(0.512851)

	[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]	2.28%	7.35%	9.63%
Blue Chip Consensus Forecast (Q1 2020 - Q1 2021) [5]	2.36%	7.31%	9.67%
Blue Chip Consensus Forecast (2021-2025) [6]	3.20%	6.83%	10.03%
AVERAGE			9.77%

Notes:
[1] Source: Regulatory Research Associates, cases up until November 29, 2019
[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
[5] Source: Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.086405 + (-0.565886 x Column [7])
[9] Equals Column [7] + Column [8]

Docket No. UE 374
Exhibit PAC/410
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Expected Earnings Analysis

February 2020

EXPECTED EARNINGS ANALYSIS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Value Line ROE 2022-2024	Value Line Total Capital 2018	Value Line Common Equity Ratio 2018	Total Equity 2018	Value Line Total Capital 2022-2024	Value Line Common Equity Ratio 2022-2024	Total Equity 2022-2024	Compound Annual Growth Rate	Adjustment Factor	Adjusted Return on Common Equity
ALLETE, Inc.	ALE	9.50%	3,584	60.10%	2,154	4,275	59.00%	2,522	3.21%	1.016	9.65%
Alliant Energy Corporation	LNT	10.00%	9,832	46.70%	4,592	12,000	48.00%	5,760	4.64%	1.023	10.23%
Ameren Corporation	AEE	10.50%	15,632	48.80%	7,628	21,000	50.50%	10,605	6.81%	1.033	10.85%
American Electric Power Company, Inc.	AEP	10.50%	40,677	46.80%	19,037	53,000	46.50%	24,645	5.30%	1.026	10.77%
Avista Corporation	AVA	8.00%	3,580	49.50%	1,772	4,600	50.00%	2,300	5.35%	1.026	8.21%
CenterPoint Energy, Inc.	CNP	10.00%	16,740	37.50%	6,278	26,700	45.00%	12,015	13.86%	1.065	10.65%
CMS Energy Corporation	CMS	14.00%	15,476	30.70%	4,751	20,000	36.50%	7,300	8.97%	1.043	14.60%
Dominion Resources, Inc.	D	13.00%	51,251	39.20%	20,090	83,800	41.00%	34,358	11.33%	1.054	13.70%
DTE Energy Company	DTE	10.50%	22,371	45.80%	10,246	32,300	45.50%	14,697	7.48%	1.036	10.88%
Duke Energy Corporation	DUK	8.50%	94,940	46.20%	43,862	120,500	44.50%	53,623	4.10%	1.020	8.67%
Entergy Corporation	ETR	11.00%	24,602	35.90%	8,832	30,600	40.00%	12,240	6.74%	1.033	11.36%
Evergy, Inc.	EVRG	8.50%	16,716	60.00%	10,030	18,600	47.50%	8,835	-2.50%	0.987	8.39%
FirstEnergy Corporation	FE	16.00%	24,565	27.40%	6,731	32,500	30.50%	9,913	8.05%	1.039	16.62%
IDACORP, Inc.	IDA	9.50%	4,205	56.40%	2,372	5,000	56.50%	2,825	3.56%	1.017	9.67%
NextEra Energy, Inc.	NEE	12.50%	60,926	56.00%	34,119	91,100	50.50%	46,006	6.16%	1.030	12.87%
NorthWestern Corporation	NWE	9.00%	4,065	47.80%	1,943	4,400	52.00%	2,288	3.32%	1.016	9.15%
OGE Energy Corporation	OGE	11.50%	6,902	58.00%	4,003	8,650	54.50%	4,714	3.32%	1.016	11.69%
Otter Tail Corporation	OTTR	11.00%	1,319	55.30%	729	1,950	49.50%	965	5.76%	1.028	11.31%
Pinnacle West Capital Corporation	PNW	10.50%	9,861	53.00%	5,226	11,450	55.50%	6,355	3.99%	1.020	10.71%
PNM Resources, Inc.	PNM	9.50%	4,370	38.60%	1,687	5,325	42.00%	2,237	5.80%	1.028	9.77%
Portland General Electric Company	POR	9.00%	4,684	53.50%	2,506	5,775	50.50%	2,916	3.08%	1.015	9.14%
PPL Corporation	PPL	13.00%	31,726	36.70%	11,643	37,500	45.00%	16,875	7.70%	1.037	13.48%
Southern Company	SO	12.50%	65,750	37.60%	24,722	80,000	41.00%	32,800	5.82%	1.028	12.85%
Xcel Energy Inc.	XEL	11.00%	28,025	43.60%	12,219	36,900	42.00%	15,498	4.87%	1.024	11.26%
Mean											11.10%
Median											10.81%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals [2] x [3]
[5] Source: Value Line
[6] Source: Value Line
[7] Equals [5] x [6]
[8] Equals ([7] / [4]) ^ (1/5) - 1
[9] Equals 2 x (1 + [8]) / (2 + [8])
[10] Equals [1] x [9]

Docket No. UE 374
Exhibit PAC/411
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Capital Expenditures Analysis

February 2020

2020-2024 CAPITAL EXPENDITURES AS A PERCENT OF 2018 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2018	2020	2021	2022	2023	2024	2020-24 Cap. Ex. / 2018 Net Plant
ALLETE, Inc.	ALE							
Capital Spending per Share			$7.15	$6.20	$5.25	$5.25	$5.25	
Common Shares Outstanding			51.75	51.75	51.75	51.75	51.75	
Capital Expenditures			$370.0	$320.9	$271.7	$271.7	$271.7	38.57%
Net Plant		$3,904.4						
Alliant Energy Corporation	LNT							
Capital Spending per Share			$6.50	$6.33	$6.15	$6.15	$6.15	
Common Shares Outstanding			242.00	246.00	250.00	250.00	250.00	
Capital Expenditures			$1,573.0	$1,556.0	$1,537.5	$1,537.5	$1,537.5	62.12%
Net Plant		$12,462.0						
Ameren Corporation	AEE							
Capital Spending per Share			$13.30	$11.78	$10.25	$10.25	$10.25	
Common Shares Outstanding			250.50	252.75	255.00	255.00	255.00	
Capital Expenditures			$3,331.7	$2,976.1	$2,613.8	$2,613.8	$2,613.8	62.03%
Net Plant		$22,810.0						
American Electric Power Company, Inc.	AEP							
Capital Spending per Share			$12.65	$12.58	$12.50	$12.50	$12.50	
Common Shares Outstanding			496.00	507.00	518.00	518.00	518.00	
Capital Expenditures			$6,274.4	$6,375.5	$6,475.0	$6,475.0	$6,475.0	58.21%
Net Plant		$55,099.0						
Avista Corporation	AVA							
Capital Spending per Share			$6.05	$6.03	$6.00	$6.00	$6.00	
Common Shares Outstanding			68.00	69.50	71.00	71.00	71.00	
Capital Expenditures			$411.4	$418.7	$426.0	$426.0	$426.0	45.35%
Net Plant		$4,648.9						
CenterPoint Energy, Inc.	CNP							
Capital Spending per Share			$4.95	$4.98	$5.00	$5.00	$5.00	
Common Shares Outstanding			504.00	522.00	540.00	540.00	540.00	
Capital Expenditures			$2,494.8	$2,597.0	$2,700.0	$2,700.0	$2,700.0	93.93%
Net Plant		$14,044.0						
CMS Energy Corporation	CMS							
Capital Spending per Share			$8.35	$7.93	$7.50	$7.50	$7.50	
Common Shares Outstanding			288.00	292.50	297.00	297.00	297.00	
Capital Expenditures			$2,404.8	$2,318.1	$2,227.5	$2,227.5	$2,227.5	62.92%
Net Plant		$18,126.0						
Dominion Resources, Inc.	D							
Capital Spending per Share			$8.35	$8.05	$7.75	$7.75	$7.75	
Common Shares Outstanding			828.00	845.00	862.00	862.00	862.00	
Capital Expenditures			$6,913.8	$6,802.3	$6,680.5	$6,680.5	$6,680.5	61.87%
Net Plant		$54,560.0						
DTE Energy Company	DTE							
Capital Spending per Share			$12.75	$12.88	$13.00	$13.00	$13.00	
Common Shares Outstanding			196.00	198.00	200.00	200.00	200.00	
Capital Expenditures			$2,499.0	$2,549.3	$2,600.0	$2,600.0	$2,600.0	59.35%
Net Plant		$21,650.0						
Duke Energy Corporation	DUK							
Capital Spending per Share			$14.00	$13.25	$12.50	$12.50	$12.50	
Common Shares Outstanding			754.00	762.00	770.00	770.00	770.00	
Capital Expenditures			$10,556.0	$10,096.5	$9,625.0	$9,625.0	$9,625.0	54.01%
Net Plant		$91,694.0						
Entergy Corporation	ETR							
Capital Spending per Share			$19.55	$19.90	$20.25	$20.25	$20.25	
Common Shares Outstanding			200.00	205.00	210.00	210.00	210.00	
Capital Expenditures			$3,910.0	$4,079.5	$4,252.5	$4,252.5	$4,252.5	64.89%
Net Plant		$31,974.0						
Evergy, Inc.	EVRG							
Capital Spending per Share			$6.30	$6.03	$5.75	$5.75	$5.75	
Common Shares Outstanding			212.00	212.00	212.00	212.00	212.00	
Capital Expenditures			$1,335.6	$1,277.3	$1,219.0	$1,219.0	$1,219.0	33.08%
Net Plant		$18,952.0						
FirstEnergy Corporation	FE							
Capital Spending per Share			$5.50	$5.38	$5.25	$5.25	$5.25	
Common Shares Outstanding			543.00	546.50	550.00	550.00	550.00	
Capital Expenditures			$2,986.5	$2,937.4	$2,887.5	$2,887.5	$2,887.5	48.77%
Net Plant		$29,911.0						
IDACORP, Inc.	IDA							
Capital Spending per Share			$6.55	$6.90	$7.25	$7.25	$7.25	
Common Shares Outstanding			50.40	50.40	50.40	50.40	50.40	
Capital Expenditures			$330.1	$347.8	$365.4	$365.4	$365.4	40.36%
Net Plant		$4,395.7						

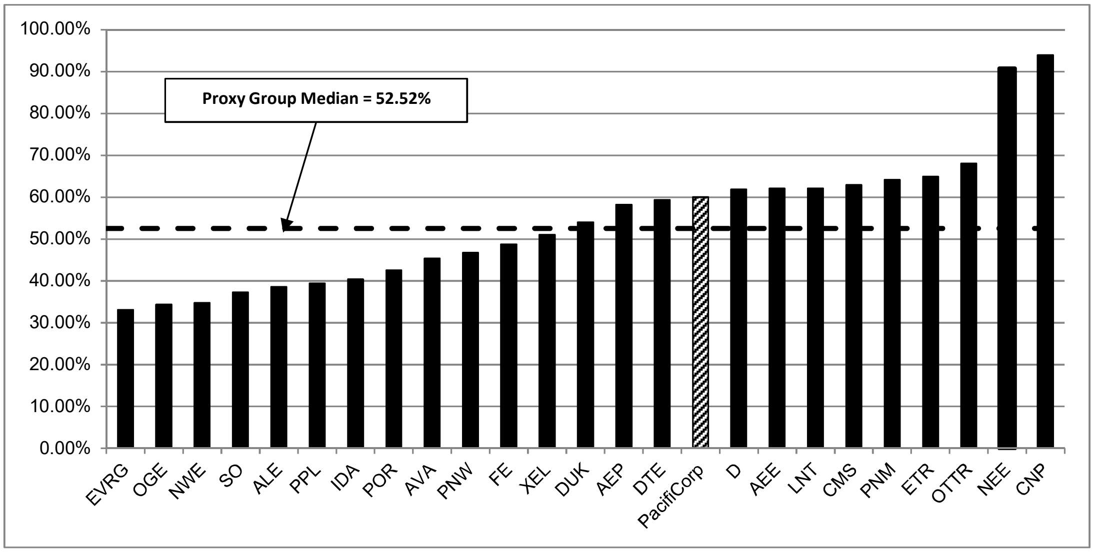
2020-2024 CAPITAL EXPENDITURES AS A PERCENT OF 2018 NET PLANT

($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2018	2020	2021	2022	2023	2024	2020-24 Cap. Ex. / 2018 Net Plant
NextEra Energy, Inc.	NEE							
Capital Spending per Share			$25.05	$25.65	$26.25	$26.25	$26.25	
Common Shares Outstanding			489.00	492.00	495.00	495.00	495.00	
Capital Expenditures			$12,249.5	$12,619.8	$12,993.8	$12,993.8	$12,993.8	90.78%
Net Plant		$70,334.0						
NorthWestern Corporation	NWE							
Capital Spending per Share			$6.55	$6.28	$6.00	$6.00	$6.00	
Common Shares Outstanding			50.65	50.88	51.10	51.10	51.10	
Capital Expenditures			$331.8	$319.2	$306.6	$306.6	$306.6	34.74%
Net Plant		$4,521.3						
OGE Energy Corporation	OGE							
Capital Spending per Share			$2.90	$2.95	$3.00	$3.00	$3.00	
Common Shares Outstanding			200.00	200.00	200.00	200.00	200.00	
Capital Expenditures			$580.0	$590.0	$600.0	$600.0	$600.0	34.36%
Net Plant		$8,643.8						
Otter Tail Corporation	OTTR							
Capital Spending per Share			$9.05	$6.28	$3.50	$3.50	$3.50	
Common Shares Outstanding			41.50	41.65	41.80	41.80	41.80	
Capital Expenditures			$375.6	$261.4	$146.3	$146.3	$146.3	68.04%
Net Plant		$1,581.1						
Pinnacle West Capital Corporation	PNW							
Capital Spending per Share			$11.05	$11.40	$11.75	$11.75	$11.75	
Common Shares Outstanding			112.50	113.25	114.00	114.00	114.00	
Capital Expenditures			$1,243.1	$1,291.1	$1,339.5	$1,339.5	$1,339.5	46.70%
Net Plant		$14,030.0						
PNM Resources, Inc.	PNM							
Capital Spending per Share			$8.65	$8.20	$7.75	$7.75	$7.75	
Common Shares Outstanding			81.00	83.00	85.00	85.00	85.00	
Capital Expenditures			$700.7	$680.6	$658.8	$658.8	$658.8	64.14%
Net Plant		$5,234.6						
Portland General Electric Company	POR							
Capital Spending per Share			$8.30	$7.03	$5.75	$5.75	$5.75	
Common Shares Outstanding			89.55	89.78	90.00	90.00	90.00	
Capital Expenditures			$743.3	$630.7	$517.5	$517.5	$517.5	42.49%
Net Plant		$6,887.0						
PPL Corporation	PPL							
Capital Spending per Share			$4.05	$3.65	$3.25	$3.25	$3.25	
Common Shares Outstanding			773.00	776.50	780.00	780.00	780.00	
Capital Expenditures			$3,130.7	$2,834.2	$2,535.0	$2,535.0	$2,535.0	39.38%
Net Plant		$34,458.0						
Southern Company	SO							
Capital Spending per Share			$6.50	$5.88	$5.25	$5.25	$5.25	
Common Shares Outstanding			1050.00	1065.00	1080.00	1080.00	1080.00	
Capital Expenditures			$6,825.0	$6,256.9	$5,670.0	$5,670.0	$5,670.0	37.24%
Net Plant		$80,797.0						
Xcel Energy Inc.	XEL							
Capital Spending per Share			$6.85	$7.05	$7.25	$7.25	$7.25	
Common Shares Outstanding			526.00	528.00	530.00	530.00	530.00	
Capital Expenditures			$3,603.1	$3,722.4	$3,842.5	$3,842.5	$3,842.5	51.03%
Net Plant		$36,944.0						
PacifiCorp	PacifiCorp							
Capital Expenditures [8]			$2,900.00	$1,400.00	$2,800.00	$2,400.00	$1,300.00	60.00%
Net Plant [9]		$18,000.0						
PacifiCorp CapEx Total (2020 - 2024)								$10,800.0
PacifiCorp CapEx Annual Average								$2,160.0
Proxy Group Median								52.52%
PacifiCorp as % Proxy Group Median								1.14

Notes:
[1] - [6] Source: Value Line, dated September 13, 2019, October 25, 2019 and November 15, 2019.
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Source: Company Provided Data
[9] Source: Company Provided Data

2020-2024 CAPITAL EXPENDITURES AS A PERCENT OF 2018 NET PLANT



Projected CAPEX / 2018 Net Plant

Rank	Company		2020-2024
1	Evergy, Inc.	EVRG	33.08%
2	OGE Energy Corporation	OGE	34.36%
3	NorthWestern Corporation	NWE	34.74%
4	Southern Company	SO	37.24%
5	ALLETE, Inc.	ALE	38.57%
6	PPL Corporation	PPL	39.38%
7	IDACORP, Inc.	IDA	40.36%
8	Portland General Electric Company	POR	42.49%
9	Avista Corporation	AVA	45.35%
10	Pinnacle West Capital Corporation	PNW	46.70%
11	FirstEnergy Corporation	FE	48.77%
12	Xcel Energy Inc.	XEL	51.03%
13	Duke Energy Corporation	DUK	54.01%
14	American Electric Power Company, Inc.	AEP	58.21%
15	DTE Energy Company	DTE	59.35%
16	PacifiCorp	PacifiCorp	60.00%
17	Dominion Resources, Inc.	D	61.87%
18	Ameren Corporation	AEE	62.03%
19	Alliant Energy Corporation	LNT	62.12%
20	CMS Energy Corporation	CMS	62.92%
21	PNM Resources, Inc.	PNM	64.14%
22	Entergy Corporation	ETR	64.89%
23	Otter Tail Corporation	OTTR	68.04%
24	NextEra Energy, Inc.	NEE	90.78%
25	CenterPoint Energy, Inc.	CNP	93.93%
	Proxy Group Median		52.52%
	PacifiCorp/Proxy Group		1.14

Notes:
Source: Exhibit PAC/211, pages 1-2 col. [7]

Docket No. UE 374
Exhibit PAC/412
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Regulatory Risk Analysis

February 2020

COMPARISON OF PACIFIC POWER AND PROXY GROUP COMPANIES
RISK ASSESSMENT

Proxy Group Company	Operation State	Operation	[1] Fuel Cost Recovery Mechanism	[2] Test Year	[3] Rate Base	[4] Revenue Decoupling	[5] Capital Cost Recovery Mechanism
ALLETE, Inc.	Minnesota	Electric	Yes	Fully Forecast	Average	No	No
Alliant Energy Corporation	Iowa	Electric	Yes	Historical	Average	No	No
	Iowa	Gas	Yes	Historical	Average	No	No
	Wisconsin	Electric	Yes	Fully Forecast	Average	No	No
	Wisconsin	Gas	Yes	Fully Forecast	Average	No	No
Ameren Corporation	Illinois	Electric	N/A	Historical	Year End	No	No
	Illinois	Gas	Yes	Fully Forecast	Average	Partial	Yes
	Missouri	Electric	Yes - Sharing Band	Historical	Year End	Partial	Yes
	Missouri	Gas	Yes	Historical	Year End	Partial	Yes
American Electric Power Company, Inc.	Arkansas	Electric	Yes	Partially Forecast	Year End	Partial	Yes
	Indiana	Electric	Yes	Fully Forecast	Year End	Partial	Yes
	Kentucky	Electric	Yes	Fully Forecast	Year End	Partial	No
	Louisiana	Electric	Yes	Historical	Year End	Partial	No
	Michigan	Electric	Yes	Fully Forecast	Average	No	No
	Ohio	Electric	N/A	Partially Forecast	Year End	Partial	Yes
	Oklahoma	Electric	Yes	Historical	Year End	Partial	Yes
	Tennessee	Electric	Yes	Fully Forecast	Average	No	No
	Texas	Electric	N/A	Historical	Year End	No	Yes
	Virginia	Electric	Yes	Historical	Year End	No	Yes
	West Virginia	Electric	Yes	Historical	Average	No	No
Avista Corporation	Alaska	Electric	Yes	Historical	Average	No	No
	Idaho	Electric	Yes - Sharing Band	Historical	Year End	Full	No
	Idaho	Gas	Yes	Historical	Year End	Full	No
	Oregon	Gas	Yes - Sharing Band	Fully Forecast	Year End	Full	No
	Washington	Electric	Yes - Sharing Band	Historical	Average	Partial	No
	Washington	Gas	Yes	Historical	Average	Partial	No
CenterPoint Energy, Inc.	Arkansas	Gas	Yes	Fully Forecast	Year End	Full	Yes
	Indiana	Electric	Yes	Historical	Year End	Partial	Yes
	Indiana	Gas	Yes	Historical	Year End	Full	Yes
	Louisiana	Gas	Yes	Historical	Average	Partial	No
	Minnesota	Gas	Yes	Fully Forecast	Average	Partial	No
	Ohio [6]	Gas	N/A	Partially Forecast	Year End	Full	Yes
	Oklahoma	Gas	Yes	Historical	Year End	Partial	No
	Texas	Electric	N/A	Historical	Year End	No	Yes
	Texas	Gas	Yes	Historical	Year End	No	Yes
CMS Energy Corporation	Michigan	Electric	Yes	Fully Forecast	Average	No	No
	Michigan	Gas	Yes	Fully Forecast	Average	Partial	Yes
Dominion Resources, Inc.	North Carolina	Electric	Yes	Historical	Year End	No	No
	North Carolina	Gas	Yes	Historical	Year End	Full	Yes
	Ohio [6]	Gas	N/A	Partially Forecast	Year End	Full	Yes
	South Carolina	Electric	Yes	Historical	Year End	No	Yes
	South Carolina	Gas	Yes	Historical	Year End	Partial	No
	Utah	Gas	Yes	Fully Forecast	Average	Full	Yes
	Virginia	Electric	Yes	Historical	Year End	No	Yes
	West Virginia	Gas	Yes	Historical	Average	No	Yes
	Wyoming	Gas	Yes	Historical	Year End	Partial	No

COMPARISON OF PACIFIC POWER AND PROXY GROUP COMPANIES
RISK ASSESSMENT

			[1]	[2]	[3]	[4]	[5]
Proxy Group Company	**Operation State**	**Operation**	**Fuel Cost Recovery Mechanism**	**Test Year**	**Rate Base**	**Revenue Decoupling**	**Capital Cost Recovery Mechanism**
DTE Energy Company	Michigan	Electric	Yes	Fully Forecast	Average	No	No
	Michigan	Gas	Yes	Fully Forecast	Average	Partial	Yes
Duke Energy Corporation	Florida	Electric	Yes	Fully Forecast	Average	No	Yes
	Indiana	Electric	Yes	Historical	Year End	Partial	Yes
	Kentucky	Electric	Yes	Fully Forecast	Average	Partial	No
	Kentucky	Gas	Yes	Fully Forecast	Average	Partial	No
	North Carolina	Electric	Yes	Historical	Year End	No	No
	North Carolina	Gas	Yes	Historical	Year End	Full	Yes
	Ohio	Electric	N/A	Partially Forecast	Year End	Partial	Yes
	Ohio [6]	Gas	Yes	Partially Forecast	Year End	Full	Yes
	South Carolina	Electric	Yes	Historical	Year End	No	No
	South Carolina	Gas	Yes	Historical	Year End	Partial	No
	Tennessee	Gas	Yes	Fully Forecast	Average	Partial	Yes
Entergy Corporation	Arkansas	Electric	Yes	Fully Forecast	Average	Partial	Yes
	Louisiana NOCC	Electric	Yes	Historical	Year End	Partial	Yes
	Louisiana NOCC	Gas	Yes	Historical	Year End	No	No
	Louisiana PSC	Electric	Yes	Historical	Average	Partial	Yes
	Louisiana PSC	Gas	Yes	Historical	Average	Partial	Yes
	Mississippi	Electric	Yes	Fully Forecast	Average	Partial	No
	Texas	Electric	Yes	Historical	Year End	No	Yes
FirstEnergy Corp.	Maryland	Electric	N/A	Partially Forecast	Average	No	Yes
	New Jersey	Electric	N/A	Partially Forecast	Year End	No	Yes
	Ohio	Electric	N/A	Partially Forecast	Year End	Partial	Yes
	Pennsylvania	Electric	N/A	Fully Forecast	Year End	No	Yes
	West Virginia	Electric	Yes	Historical	Average	No	Yes
Evergy, Inc.	Kansas	Electric	Yes	Historical	Year End	Partial	Yes
	Missouri	Electric	Yes - Sharing Band	Historical	Year End	Partial	Yes
IDACORP, Inc.	Idaho	Electric	Yes - Sharing Band	Partially Forecast	Year End	Full	No
	Oregon	Electric	Yes - Sharing Band	Partially Forecast	Average	No	No
NextEra Energy, Inc.	Florida	Electric	Yes	Fully Forecast	Average	No	Yes
	Florida	Gas	Yes	Fully Forecast	Average	No	Yes
	Texas	Electric	N/A	Historical	Year End	No	Yes
NorthWestern Corporation	Montana	Electric	Yes - Sharing Band	Historical	Average	No	No
	Montana	Gas	Yes	Historical	Average	No	No
	Nebraska	Gas	Yes	Historical	Year End	No	No
	South Dakota	Electric	Yes	Historical	Average	No	No
	South Dakota	Gas	Yes	Historical	Average	No	No
OGE Energy Corporation	Arkansas	Electric	Yes	Fully Forecast	Year End	Partial	Yes
	Oklahoma	Electric	Yes	Partially Forecast	Year End	Partial	Yes
Otter Tail Corporation	Minnesota	Electric	Yes	Fully Forecast	Average	No	No
	North Dakota	Electric	Yes	Fully Forecast	Average	No	Yes
	South Dakota	Electric	Yes	Historical	Average	No	Yes
Pinnacle West Capital Corporation	Arizona	Electric	Yes - Sharing Band	Historical	Year End	Partial	No
PNM Resources, Inc.	New Mexico	Electric	Yes	Fully Forecast	Average	No	Yes
	Texas	Electric	N/A	Historical	Year End	No	Yes
Portland General Electric Company	Oregon	Electric	Yes - Sharing Band	Fully Forecast	Year End	Partial	No
PPL Corporation	Kentucky	Electric	Yes	Fully Forecast	Year End	Partial	No
	Kentucky	Gas	Yes	Fully Forecast	Year End	Partial	Yes
	Pennsylvania	Electric	N/A	Fully Forecast	Year End	No	Yes
	Virginia	Electric	Yes	Historical	Year End	No	No

COMPARISON OF PACIFIC POWER AND PROXY GROUP COMPANIES
RISK ASSESSMENT

			[1]		[2]		[3]		[4]		[5]
Proxy Group Company	**Operation State**	**Operation**	**Fuel Cost Recovery Mechanism**		**Test Year**		**Rate Base**		**Revenue Decoupling**		**Capital Cost Recovery Mechanism**
Southern Company	Alabama	Electric	Yes		Fully Forecast		Average		No		Yes
	Georgia	Electric	Yes		Fully Forecast		Average		No		Yes
	Georgia [6]	Gas	N/A		Fully Forecast		Average		Full		Yes
	Illinois	Gas	Yes		Fully Forecast		Average		Partial		Yes
	Mississippi	Electric	Yes		Fully Forecast		Average		Partial		No
	Tennessee	Gas	Yes		Fully Forecast		Average		Full		No
	Virginia	Gas	Yes		Historical		Year End		Partial		Yes
Xcel Energy Inc.	Colorado	Electric	Yes		Historical		Year End		No		Yes
	Colorado	Gas	Yes		Historical		Average		Partial		Yes
	Minnesota	Electric	Yes		Fully Forecast		Average		Partial		No
	Minnesota	Gas	Yes		Fully Forecast		Average		No		Yes
	New Mexico	Electric	Yes		Historical		Year End		No		No
	North Dakota	Electric	Yes		Fully Forecast		Average		No		Yes
	North Dakota [6]	Gas	Yes		Fully Forecast		Average		Full		No
	South Dakota	Electric	Yes		Historical		Average		Partial		Yes
	Texas	Electric	Yes		Historical		Year End		No		Yes
	Wisconsin	Electric	Yes		Fully Forecast		Average		No		No
	Wisconsin	Gas	Yes		Fully Forecast		Average		No		No
								Revenue Decoupling		Capital Cost Recovery	
Proxy Group Average		Yes	89	Fully Forecast	45	Year End	59	Full	15	Yes	63
		No	0	Partially Forecast	12	Average	55	Partial	45	No	51
		N/A	15	Historical	57			No	54		
		Yes - Sharing Band	10								
		Yes / N/A	91.23%	Forecast	50.00%	Year End	51.75%	RDM	52.63%	CCRM	55.26%
PacifiCorp [7]	Oregon	Electric	Yes - Sharing Band		Fully Forecast		Average		No		Yes

Notes:
[1] Source: 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.
[2] Source: "Alternative Regulation for Evolving Utility Challenges," Prepared by Pacific Economics Group Research for Edison Electric Institute, Table 6, November 2015; S&P RRA Research; Company Investor Presentations.
[3] Source: Regulatory Research Associates, effective as of November 29, 2019.
[4] - [5] Source: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019.
[6] Operations classified as full revenue decoupling since the company operates under a straight fixed-variable rate design.
[7] Data provided by PacifiCorp

Docket No. UE 374
Exhibit PAC/413
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Capital Structure Analysis

February 2020

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2019Q3	2019Q2	2019Q1	2018Q4	2018Q3	2018Q2	2018Q1	2017Q4	Average
ALLETE, Inc.	ALE	59.30%	60.87%	60.80%	61.27%	60.33%	60.26%	60.50%	60.15%	60.43%
Alliant Energy Corporation	LNT	50.48%	49.65%	52.17%	52.11%	49.88%	49.85%	48.68%	48.74%	50.19%
Ameren Corporation	AEE	53.13%	52.48%	52.27%	52.18%	52.72%	51.43%	52.38%	52.02%	52.33%
American Electric Power Company, Inc.	AEP	48.83%	48.04%	48.72%	48.55%	47.52%	47.93%	48.54%	48.88%	48.37%
Avista Corporation	AVA	50.33%	51.40%	51.18%	49.89%	49.55%	49.74%	51.16%	50.75%	50.50%
CenterPoint Energy, Inc.	CNP	44.24%	42.77%	41.95%	40.59%	38.57%	37.51%	36.72%	37.47%	39.98%
CMS Energy Corporation	CMS	51.57%	53.50%	52.38%	50.14%	52.86%	52.71%	52.97%	52.10%	52.28%
Dominion Resources, Inc.	D	53.43%	52.20%	51.50%	50.52%	52.45%	51.81%	50.53%	51.07%	51.69%
DTE Energy Company	DTE	49.40%	48.76%	48.69%	50.96%	49.97%	49.23%	51.12%	51.02%	49.89%
Duke Energy Corporation	DUK	52.62%	53.12%	52.16%	52.71%	52.85%	53.04%	52.88%	53.01%	52.80%
Entergy Corporation	ETR	47.64%	46.80%	47.03%	48.73%	48.31%	48.00%	46.00%	47.41%	47.49%
Evergy, Inc.	EVRG	59.75%	60.09%	57.72%	59.30%	59.49%	58.46%	58.59%	58.44%	58.98%
FirstEnergy Corporation	FE	57.62%	57.81%	58.37%	58.90%	59.48%	59.00%	57.54%	56.97%	58.21%
IDACORP, Inc.	IDA	55.20%	54.58%	54.36%	54.25%	54.25%	53.44%	51.37%	54.22%	53.96%
NextEra Energy, Inc.	NEE	59.15%	61.29%	63.51%	63.95%	64.01%	60.34%	60.63%	59.41%	61.54%
NorthWestern Corporation	NWE	47.80%	48.07%	48.74%	47.88%	48.36%	48.41%	47.48%	49.89%	48.33%
OGE Energy Corporation	OGE	54.96%	53.47%	55.38%	53.20%	53.05%	54.25%	53.59%	53.36%	53.91%
Otter Tail Corporation	OTTR	55.43%	53.75%	53.90%	53.58%	53.49%	53.11%	52.67%	57.34%	54.16%
Pinnacle West Capital Corporation	PNW	54.25%	54.41%	54.48%	54.36%	53.68%	53.71%	53.18%	53.14%	53.90%
PNM Resources, Inc.	PNM	46.31%	46.03%	43.88%	47.91%	49.43%	48.72%	49.00%	48.80%	47.51%
Portland General Electric Company	POR	51.78%	51.56%	50.60%	50.19%	50.51%	50.29%	50.14%	49.80%	50.61%
PPL Corporation	PPL	53.93%	53.84%	55.18%	54.92%	54.85%	54.51%	54.60%	54.60%	54.55%
Southern Company	SO	53.24%	54.15%	54.05%	53.92%	52.64%	50.95%	50.90%	47.76%	52.20%
Xcel Energy Inc.	XEL	54.13%	55.25%	54.92%	54.48%	54.29%	53.51%	54.40%	54.23%	54.40%
MEAN		52.69%	52.66%	52.66%	52.69%	52.61%	52.09%	51.90%	52.11%	52.43%
LOW		44.24%	42.77%	41.95%	40.59%	38.57%	37.51%	36.72%	37.47%	39.98%
HIGH		59.75%	61.29%	63.51%	63.95%	64.01%	60.34%	60.63%	60.15%	61.54%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2019Q3	2019Q2	2019Q1	2018Q4	2018Q3	2018Q2	2018Q1	2017Q4	Average
ALLETE (Minnesota Power)	ALE	59.33%	60.94%	60.87%	61.39%	60.43%	60.33%	60.38%	60.04%	60.46%
Superior Water, Light and Power Company	ALE	58.03%	58.38%	58.19%	56.86%	56.58%	57.34%	65.80%	64.99%	59.52%
Interstate Power and Light Company	LNT	48.56%	50.11%	51.59%	51.70%	47.96%	48.62%	48.01%	48.37%	49.37%
Wisconsin Power and Light Company	LNT	53.40%	49.01%	53.03%	52.69%	52.62%	51.52%	49.57%	49.23%	51.38%
Ameren Illinois Company	AEE	54.01%	53.59%	53.19%	52.40%	52.69%	52.25%	53.71%	52.84%	53.09%
Union Electric Company	AEE	52.36%	51.49%	51.45%	51.98%	52.73%	50.77%	51.30%	51.38%	51.68%
AEP Texas, Inc.	AEP	46.97%	46.32%	47.54%	45.38%	43.80%	43.20%	46.75%	45.14%	45.64%
Appalachian Power Company	AEP	48.74%	48.19%	47.77%	49.51%	49.30%	48.93%	49.35%	48.72%	48.81%
Indiana Michigan Power Company	AEP	46.51%	45.83%	45.43%	44.62%	44.53%	44.15%	46.64%	46.33%	45.50%
Kentucky Power Company	AEP	46.94%	46.50%	46.42%	45.72%	45.28%	44.89%	44.40%	43.52%	45.46%
Kingsport Power Company	AEP	54.24%	50.18%	51.54%	50.79%	50.71%	47.69%	47.28%	46.53%	49.87%
Ohio Power Company	AEP	53.63%	52.92%	58.86%	57.80%	56.85%	57.11%	52.91%	58.63%	56.09%
Public Service Company of Oklahoma	AEP	49.89%	48.02%	47.19%	49.16%	49.55%	48.59%	48.10%	48.50%	48.62%
Southwestern Electric Power Company	AEP	48.63%	47.45%	47.59%	46.97%	43.43%	47.91%	47.72%	48.52%	47.28%
Wheeling Power Company	AEP	53.66%	53.83%	54.27%	54.62%	54.70%	54.19%	54.27%	54.26%	54.23%
Avista Corporation	AVA	50.33%	51.40%	51.18%	49.89%	49.55%	49.74%	51.16%	50.75%	50.50%
CenterPoint Energy Houston Electric, LLC	CNP	40.97%	39.39%	38.49%	36.25%	34.77%	33.37%	32.45%	33.26%	36.12%
Southern Indiana Gas and Electric Company, Inc.	CNP	59.46%	58.80%	58.45%	58.54%	55.39%	56.74%	56.62%	56.46%	57.56%
Consumers Energy Company	CMS	51.57%	53.50%	52.38%	50.14%	52.86%	52.71%	52.97%	52.10%	52.28%
Virginia Electric and Power Company	D	53.33%	53.30%	52.42%	52.62%	53.64%	52.81%	51.03%	51.71%	52.61%
South Carolina Electric & Gas Co.	D	53.79%	48.67%	48.52%	44.88%	49.63%	49.44%	49.30%	49.54%	49.22%
DTE Electric Company	DTE	49.40%	48.76%	48.69%	50.96%	49.97%	49.23%	51.12%	51.02%	49.89%
Duke Energy Carolinas, LLC	DUK	51.80%	52.94%	52.32%	51.78%	52.64%	52.10%	51.70%	52.98%	52.28%
Duke Energy Florida, LLC	DUK	52.82%	51.55%	50.56%	50.04%	49.65%	48.79%	49.92%	49.25%	50.32%
Duke Energy Indiana, LLC	DUK	51.52%	54.83%	54.29%	53.26%	52.79%	52.64%	52.54%	51.94%	52.98%
Duke Energy Kentucky, Inc.	DUK	45.44%	53.04%	52.81%	51.95%	56.58%	55.79%	53.72%	53.11%	52.80%
Duke Energy Ohio, Inc.	DUK	64.90%	64.45%	59.29%	68.09%	67.73%	67.10%	66.06%	66.24%	65.48%
Duke Energy Progress, LLC	DUK	50.86%	50.09%	49.60%	51.00%	50.76%	53.22%	52.82%	52.27%	51.33%
Entergy Arkansas, Inc.	ETR	47.72%	46.49%	47.04%	49.42%	49.13%	48.03%	45.60%	45.67%	47.39%
Entergy Louisiana, LLC	ETR	47.13%	46.32%	45.79%	47.37%	46.77%	46.97%	44.58%	47.43%	46.55%
Entergy Mississippi, Inc.	ETR	48.35%	44.93%	49.41%	49.11%	49.70%	48.71%	47.93%	47.45%	48.20%
Entergy New Orleans, LLC	ETR	50.33%	49.02%	48.00%	47.91%	47.37%	49.91%	49.02%	48.75%	48.79%
Entergy Texas, Inc.	ETR	48.13%	50.79%	50.13%	53.46%	52.61%	51.38%	50.79%	50.45%	50.97%
Kansas City Power & Light Company	EVRG	50.43%	49.62%	46.04%	49.49%	49.50%	48.88%	49.25%	49.15%	49.05%
Kansas Gas and Electric Company	EVRG	81.84%	81.49%	75.13%	74.97%	74.91%	74.45%	74.29%	74.18%	76.41%
KCP&L Greater Missouri Operations Company	EVRG	51.18%	51.74%	52.68%	54.71%	55.70%	52.03%	52.63%	52.40%	52.88%
Westar Energy (KPL)	EVRG	57.66%	59.18%	58.80%	59.08%	59.34%	58.68%	58.75%	58.74%	58.78%
Cleveland Electric Illuminating Company	FE	55.74%	55.49%	55.54%	55.44%	56.50%	56.31%	55.48%	55.27%	55.72%
Jersey Central Power & Light Company	FE	68.74%	68.23%	68.08%	69.46%	69.34%	68.81%	65.52%	65.30%	67.93%
Metropolitan Edison Company	FE	49.72%	48.46%	47.78%	53.21%	54.25%	53.10%	52.18%	52.33%	51.38%
Monongahela Power Company	FE	49.98%	49.07%	49.05%	48.87%	50.71%	51.53%	50.57%	49.15%	49.87%
Ohio Edison Company	FE	69.16%	71.42%	70.82%	69.93%	69.14%	67.33%	66.89%	64.91%	68.70%
Pennsylvania Electric Company	FE	51.78%	50.93%	53.85%	53.89%	54.01%	53.90%	53.09%	52.06%	52.94%
Pennsylvania Power Company	FE	53.09%	51.71%	50.69%	49.03%	58.27%	56.89%	55.70%	53.82%	53.65%
Potomac Edison Company	FE	53.69%	52.99%	53.29%	52.35%	52.92%	52.65%	52.64%	51.59%	52.77%
Toledo Edison Company	FE	60.76%	60.57%	60.78%	60.43%	62.25%	62.25%	60.60%	60.04%	60.96%
West Penn Power Company	FE	46.11%	50.63%	54.68%	53.50%	53.14%	52.09%	51.09%	52.82%	51.76%
Idaho Power Co.	IDA	55.20%	54.58%	54.36%	54.25%	54.25%	53.44%	51.37%	54.22%	53.96%
Florida Power & Light Company	NEE	59.78%	61.30%	64.03%	64.37%	64.78%	60.84%	61.23%	59.93%	62.03%
Gulf Power Company	NEE	52.52%	61.15%	58.06%	59.73%	55.34%	54.90%	54.27%	54.19%	56.27%
NorthWestern Corporation	NWE	47.80%	48.07%	48.74%	47.88%	48.36%	48.41%	47.48%	49.89%	48.33%
Oklahoma Gas and Electric Company	OGE	54.96%	53.47%	55.38%	53.20%	53.05%	54.25%	53.59%	53.36%	53.91%
Otter Tail Corporation	OTTR	55.43%	53.75%	53.90%	53.58%	53.49%	53.11%	52.67%	57.34%	54.16%
Arizona Public Service Company	PNW	54.25%	54.41%	54.48%	54.36%	53.68%	53.71%	53.18%	53.14%	53.90%
Public Service Company of New Mexico	PNM	45.16%	43.69%	43.29%	45.45%	47.83%	46.51%	46.03%	45.89%	45.48%
Texas-New Mexico Power Company	PNM	48.89%	51.47%	45.11%	53.95%	53.69%	54.56%	57.21%	56.90%	52.72%
Portland General Electric Company	POR	51.78%	51.56%	50.60%	50.19%	50.51%	50.29%	50.14%	49.80%	50.61%
Kentucky Utilities Company	PPL	52.97%	52.81%	55.44%	54.85%	54.76%	54.51%	54.08%	54.00%	54.18%
Louisville Gas and Electric Company	PPL	54.10%	53.88%	56.16%	55.80%	55.35%	54.97%	54.46%	55.42%	55.02%
PPL Electric Utilities Corporation	PPL	54.44%	54.51%	54.52%	54.52%	54.65%	54.28%	55.04%	54.57%	54.57%
Alabama Power Company	SO	50.60%	51.63%	51.31%	46.88%	47.24%	46.62%	47.91%	46.12%	48.54%
Georgia Power Company	SO	55.38%	56.39%	56.43%	59.02%	57.27%	54.97%	53.81%	50.06%	55.42%
Mississippi Power Company	SO	50.23%	49.87%	49.73%	50.35%	44.81%	43.41%	42.54%	38.96%	46.24%
Northern States Power Company - MN	XEL	51.79%	53.66%	53.64%	52.81%	52.64%	52.61%	52.59%	52.38%	52.77%
Northern States Power Company - WI	XEL	53.56%	53.49%	53.59%	53.60%	48.45%	53.85%	53.79%	53.36%	52.96%
Public Service Company of Colorado	XEL	56.35%	57.53%	56.68%	56.31%	56.08%	54.17%	56.67%	56.50%	56.29%
Southwestern Public Service Company	XEL	54.21%	54.14%	54.13%	54.17%	56.29%	53.88%	53.54%	53.55%	54.24%

Notes:
[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of Operating Subsidiaries.
[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2019Q3	2019Q2	2019Q1	2018Q4	2018Q3	2018Q2	2018Q1	2017Q4	Average
ALLETE, Inc.	ALE	40.70%	39.13%	39.20%	38.73%	39.67%	39.74%	39.50%	39.85%	39.57%
Alliant Energy Corporation	LNT	47.71%	48.49%	45.88%	45.89%	48.13%	48.04%	49.13%	49.06%	47.79%
Ameren Corporation	AEE	45.96%	46.60%	46.81%	46.87%	46.33%	47.61%	46.61%	46.95%	46.72%
American Electric Power Company, Inc.	AEP	51.17%	51.96%	51.28%	51.45%	52.48%	52.07%	51.46%	51.12%	51.63%
Avista Corporation	AVA	49.67%	48.60%	48.82%	50.11%	50.45%	50.26%	48.84%	49.25%	49.50%
Exelon Corporation	EXC	55.76%	57.23%	58.05%	59.41%	61.43%	62.49%	63.28%	62.53%	60.02%
CMS Energy Corporation	CMS	48.18%	46.24%	47.35%	49.59%	46.85%	47.01%	46.73%	47.60%	47.44%
Dominion Resources, Inc.	D	46.57%	47.80%	48.50%	49.48%	47.55%	48.19%	49.47%	48.93%	48.31%
DTE Energy Company	DTE	50.60%	51.24%	51.31%	49.04%	50.03%	50.77%	48.88%	48.98%	50.11%
Duke Energy Corporation	DUK	47.38%	46.88%	47.84%	47.29%	47.15%	46.96%	47.12%	46.99%	47.20%
Entergy Corporation	ETR	52.23%	53.20%	52.97%	51.27%	51.48%	51.78%	53.77%	52.36%	52.38%
Evergy, Inc.	EVRG	40.25%	39.91%	42.28%	40.70%	40.51%	41.54%	41.41%	41.56%	41.02%
FirstEnergy Corporation	FE	42.38%	42.19%	41.63%	41.10%	40.52%	41.00%	42.46%	43.03%	41.79%
IDACORP, Inc.	IDA	44.80%	45.42%	45.64%	45.75%	45.75%	46.56%	48.63%	45.78%	46.04%
NextEra Energy, Inc.	NEE	40.85%	38.71%	36.49%	36.05%	35.99%	39.66%	39.37%	40.59%	38.46%
NorthWestern Corporation	NWE	52.20%	51.93%	51.26%	52.12%	51.64%	51.59%	52.52%	50.11%	51.67%
OGE Energy Corporation	OGE	45.04%	46.53%	44.62%	46.80%	46.95%	45.75%	46.41%	46.64%	46.09%
Otter Tail Corporation	OTTR	44.57%	46.25%	46.10%	46.42%	46.51%	46.89%	47.33%	42.66%	45.84%
Pinnacle West Capital Corporation	PNW	45.75%	45.59%	45.52%	45.64%	46.32%	46.29%	46.82%	46.86%	46.10%
PNM Resources, Inc.	PNM	53.43%	53.71%	55.86%	51.82%	50.31%	51.01%	50.73%	50.92%	52.22%
Portland General Electric Company	POR	48.22%	48.44%	49.40%	49.81%	49.49%	49.71%	49.86%	50.20%	49.39%
PPL Corporation	PPL	46.07%	46.16%	44.82%	45.08%	45.15%	45.49%	45.40%	45.40%	45.45%
Southern Company	SO	46.14%	45.20%	45.30%	45.39%	46.60%	48.27%	48.33%	51.45%	47.09%
Xcel Energy Inc.	XEL	45.87%	44.75%	45.08%	45.52%	45.71%	46.49%	45.60%	45.77%	45.60%
MEAN		47.15%	47.17%	47.17%	47.14%	47.21%	47.72%	47.90%	47.69%	47.39%
LOW		40.25%	38.71%	36.49%	36.05%	35.99%	39.66%	39.37%	39.85%	38.46%
HIGH		55.76%	57.23%	58.05%	59.41%	61.43%	62.49%	63.28%	62.53%	60.02%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2019Q3	2019Q2	2019Q1	2018Q4	2018Q3	2018Q2	2018Q1	2017Q4	Average
ALLETE (Minnesota Power)	ALE	40.67%	39.06%	39.13%	38.61%	39.57%	39.67%	39.62%	39.96%	39.54%
Superior Water, Light and Power Company	ALE	41.97%	41.62%	41.81%	43.14%	43.42%	42.66%	34.20%	35.01%	40.48%
Interstate Power and Light Company	LNT	48.44%	46.70%	45.13%	44.90%	48.66%	47.72%	48.17%	47.78%	47.19%
Wisconsin Power and Light Company	LNT	46.60%	50.99%	46.97%	47.31%	47.38%	48.48%	50.43%	50.77%	48.62%
Ameren Illinois Company	AEE	45.15%	45.56%	45.95%	46.73%	46.39%	46.83%	45.31%	46.15%	46.01%
Union Electric Company	AEE	46.67%	47.52%	47.56%	47.00%	46.27%	48.24%	47.66%	47.58%	47.31%
AEP Texas, Inc.	AEP	53.03%	53.68%	52.46%	54.62%	56.20%	56.80%	53.25%	54.86%	54.36%
Appalachian Power Company	AEP	51.26%	51.81%	52.23%	50.49%	50.70%	51.07%	50.65%	51.28%	51.19%
Indiana Michigan Power Company	AEP	53.49%	54.17%	54.57%	55.38%	55.47%	55.85%	53.36%	53.67%	54.50%
Kentucky Power Company	AEP	53.06%	53.50%	53.58%	54.28%	54.72%	55.11%	55.60%	56.48%	54.54%
Kingsport Power Company	AEP	45.76%	49.82%	48.46%	49.21%	49.29%	52.31%	52.72%	53.47%	50.13%
Ohio Power Company	AEP	46.37%	47.08%	41.14%	42.20%	43.15%	42.89%	47.09%	41.37%	43.91%
Public Service Company of Oklahoma	AEP	50.11%	51.98%	52.81%	50.84%	50.45%	51.41%	51.90%	51.50%	51.38%
Southwestern Electric Power Company	AEP	51.37%	52.55%	52.41%	53.03%	56.57%	52.09%	52.28%	51.48%	52.72%
Wheeling Power Company	AEP	46.34%	46.17%	45.73%	45.38%	45.30%	45.81%	45.73%	45.74%	45.77%
Avista Corporation	AVA	49.67%	48.60%	48.82%	50.11%	50.45%	50.26%	48.84%	49.25%	49.50%
CenterPoint Energy Houston Electric, LLC	CNP	59.03%	60.61%	61.51%	63.75%	65.23%	66.63%	67.55%	66.74%	63.88%
Southern Indiana Gas and Electric Company, Inc.	CNP	40.54%	41.20%	41.55%	41.46%	44.61%	43.26%	43.38%	43.54%	42.44%
Consumers Energy Company	CMS	48.18%	46.24%	47.35%	49.59%	46.85%	47.01%	46.73%	47.60%	47.44%
Virginia Electric and Power Company	D	46.67%	46.70%	47.58%	47.38%	46.36%	47.19%	48.97%	48.29%	47.39%
South Carolina Electric & Gas Co.	D	46.20%	51.33%	51.48%	55.12%	50.37%	50.56%	50.70%	50.46%	50.78%
DTE Electric Company	DTE	50.60%	51.24%	51.31%	49.04%	50.03%	50.77%	48.88%	48.98%	50.11%
Duke Energy Carolinas, LLC	DUK	48.20%	47.06%	47.68%	48.22%	47.36%	47.90%	48.30%	47.02%	47.72%
Duke Energy Florida, LLC	DUK	47.18%	48.45%	49.44%	49.96%	50.35%	51.21%	50.08%	50.75%	49.68%
Duke Energy Indiana, LLC	DUK	48.48%	45.17%	45.71%	46.74%	47.21%	47.36%	47.46%	48.06%	47.02%
Duke Energy Kentucky, Inc.	DUK	54.56%	46.96%	47.19%	48.05%	43.42%	44.21%	46.28%	46.89%	47.20%
Duke Energy Ohio, Inc.	DUK	35.10%	35.55%	40.71%	31.91%	32.27%	32.90%	33.94%	33.76%	34.52%
Duke Energy Progress, LLC	DUK	49.14%	49.91%	50.40%	49.00%	49.24%	46.78%	47.18%	47.73%	48.67%
Entergy Arkansas, Inc.	ETR	52.28%	53.51%	52.96%	50.58%	50.35%	51.44%	53.80%	53.73%	52.33%
Entergy Louisiana, LLC	ETR	52.87%	53.68%	54.21%	52.63%	53.23%	53.03%	55.42%	52.57%	53.45%
Entergy Mississippi, Inc.	ETR	51.65%	55.07%	50.59%	50.89%	49.51%	50.49%	51.26%	51.72%	51.40%
Entergy New Orleans, LLC	ETR	49.67%	50.98%	52.00%	52.09%	52.63%	50.09%	50.98%	51.25%	51.21%
Entergy Texas, Inc.	ETR	50.84%	49.21%	49.87%	46.54%	47.39%	48.62%	49.21%	49.55%	48.91%
Kansas City Power & Light Company	EVRG	49.57%	50.38%	53.96%	50.51%	50.50%	51.12%	50.75%	50.85%	50.95%
Kansas Gas and Electric Company	EVRG	18.16%	18.51%	24.87%	25.03%	25.09%	25.55%	25.71%	25.82%	23.59%
KCP&L Greater Missouri Operations Company	EVRG	48.82%	48.26%	47.32%	45.29%	44.30%	47.97%	47.37%	47.60%	47.12%
Westar Energy (KPL)	EVRG	42.34%	40.82%	41.20%	40.92%	40.66%	41.32%	41.25%	41.26%	41.22%
Cleveland Electric Illuminating Company	FE	44.26%	44.51%	44.46%	44.56%	43.50%	43.69%	44.52%	44.73%	44.28%
Jersey Central Power & Light Company	FE	31.26%	31.77%	31.92%	30.54%	30.66%	31.19%	34.48%	34.70%	32.07%
Metropolitan Edison Company	FE	50.28%	51.54%	52.22%	46.79%	45.75%	46.90%	47.82%	47.67%	48.62%
Monongahela Power Company	FE	50.02%	50.93%	50.95%	51.13%	49.29%	48.47%	49.43%	50.85%	50.13%
Ohio Edison Company	FE	30.84%	28.58%	29.18%	30.07%	30.86%	32.67%	33.11%	35.09%	31.30%
Pennsylvania Electric Company	FE	48.22%	49.07%	46.15%	46.11%	45.99%	46.10%	46.91%	47.94%	47.06%
Pennsylvania Power Company	FE	46.91%	48.29%	49.31%	50.97%	41.73%	43.11%	44.30%	46.18%	46.35%
Potomac Edison Company	FE	46.31%	47.01%	46.71%	47.65%	47.08%	47.35%	47.36%	48.41%	47.23%
Toledo Edison Company	FE	39.24%	39.43%	39.22%	39.57%	37.75%	37.75%	39.40%	39.96%	39.04%
West Penn Power Company	FE	53.89%	49.37%	45.32%	46.50%	46.86%	47.91%	48.91%	47.18%	48.24%
Idaho Power Co.	IDA	44.80%	45.42%	45.64%	45.75%	45.75%	46.56%	48.63%	45.78%	46.04%
Florida Power & Light Company	NEE	40.22%	38.70%	35.97%	35.63%	35.22%	39.16%	38.77%	40.07%	37.97%
Gulf Power Company	NEE	47.48%	38.85%	41.94%	40.27%	44.66%	45.10%	45.73%	45.81%	43.73%
NorthWestern Corporation	NWE	52.20%	51.93%	51.26%	52.12%	51.64%	51.59%	52.52%	50.11%	51.67%
Oklahoma Gas and Electric Company	OGE	45.04%	46.53%	44.62%	46.80%	46.95%	45.75%	46.41%	46.64%	46.09%
Otter Tail Corporation	OTTR	44.57%	46.25%	46.10%	46.42%	46.51%	46.89%	47.33%	42.66%	45.84%
Arizona Public Service Company	PNW	45.75%	45.59%	45.52%	45.64%	46.32%	46.29%	46.82%	46.86%	46.10%
Public Service Company of New Mexico	PNM	54.47%	55.93%	56.33%	54.17%	51.81%	53.12%	53.60%	53.74%	54.15%
Texas-New Mexico Power Company	PNM	51.11%	48.53%	54.89%	46.05%	46.31%	45.44%	42.79%	43.10%	47.28%
Portland General Electric Company	POR	48.22%	48.44%	49.40%	49.81%	49.49%	49.71%	49.86%	50.20%	49.39%
Kentucky Utilities Company	PPL	47.03%	47.19%	44.56%	45.15%	45.24%	45.49%	45.92%	46.00%	45.82%
Louisville Gas and Electric Company	PPL	45.90%	46.12%	43.84%	44.20%	44.65%	45.03%	45.54%	44.58%	44.98%
PPL Electric Utilities Corporation	PPL	45.56%	45.49%	45.48%	45.48%	45.35%	45.72%	44.96%	45.43%	45.43%
Alabama Power Company	SO	47.74%	46.63%	46.93%	51.26%	50.91%	51.50%	50.15%	51.86%	49.62%
Georgia Power Company	SO	44.62%	43.61%	43.57%	40.98%	42.73%	45.03%	46.19%	49.94%	44.58%
Mississippi Power Company	SO	49.77%	50.13%	50.27%	49.65%	54.16%	55.55%	56.40%	60.08%	53.25%
Northern States Power Company - MN	XEL	48.21%	46.34%	46.36%	47.19%	47.36%	47.39%	47.41%	47.62%	47.23%
Northern States Power Company - WI	XEL	46.44%	46.51%	46.41%	46.40%	51.55%	46.15%	46.21%	46.64%	47.04%
Public Service Company of Colorado	XEL	43.65%	42.47%	43.32%	43.69%	43.92%	45.83%	43.33%	43.50%	43.71%
Southwestern Public Service Company	XEL	45.79%	45.86%	45.87%	45.83%	43.71%	46.12%	46.46%	46.45%	45.76%

Notes:

[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

PREFERRED EQUITY RATIO [1]

Proxy Group Company	Ticker	2019Q3	2019Q2	2019Q1	2018Q4	2018Q3	2018Q2	2018Q1	2017Q4	Average
ALLETE, Inc.	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Alliant Energy Corporation	LNT	1.81%	1.85%	1.95%	2.00%	1.99%	2.11%	2.19%	2.21%	2.01%
Ameren Corporation	AEE	0.91%	0.92%	0.93%	0.95%	0.96%	0.96%	1.01%	1.02%	0.96%
American Electric Power Company, Inc.	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Avista Corporation	AVA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CenterPoint Energy, Inc.	CNP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CMS Energy Corporation	CMS	0.25%	0.26%	0.27%	0.27%	0.29%	0.29%	0.30%	0.30%	0.28%
Dominion Resources, Inc.	D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DTE Energy Company	DTE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Corporation	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy Corporation	ETR	0.13%	0.00%	0.00%	0.00%	0.21%	0.22%	0.22%	0.23%	0.13%
Evergy, Inc.	EVRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FirstEnergy Corporation	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
IDACORP, Inc.	IDA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NextEra Energy, Inc.	NEE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NorthWestern Corporation	NWE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OGE Energy Corporation	OGE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Otter Tail Corporation	OTTR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pinnacle West Capital Corporation	PNW	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
PNM Resources, Inc.	PNM	0.25%	0.26%	0.25%	0.27%	0.26%	0.27%	0.27%	0.27%	0.26%
Portland General Electric Company	POR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
PPL Corporation	PPL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southern Company	SO	0.62%	0.65%	0.65%	0.69%	0.76%	0.78%	0.76%	0.79%	0.71%
Xcel Energy Inc.	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MEAN		0.17%	0.16%	0.17%	0.17%	0.19%	0.19%	0.20%	0.20%	0.18%
LOW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
HIGH		1.81%	1.85%	1.95%	2.00%	1.99%	2.11%	2.19%	2.21%	2.01%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2019Q3	2019Q2	2019Q1	2018Q4	2018Q3	2018Q2	2018Q1	2017Q4	Average
ALLETE (Minnesota Power)	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Superior Water, Light and Power Company	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Interstate Power and Light Company	LNT	2.99%	3.18%	3.28%	3.41%	3.37%	3.66%	3.81%	3.85%	3.44%
Wisconsin Power and Light Company	LNT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ameren Illinois Company	AEE	0.84%	0.85%	0.86%	0.87%	0.92%	0.92%	0.98%	1.00%	0.91%
Union Electric Company	AEE	0.97%	0.99%	0.99%	1.01%	1.00%	0.99%	1.04%	1.04%	1.00%
AEP Texas, Inc.	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Appalachian Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Indiana Michigan Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kentucky Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kingsport Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ohio Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Public Service Company of Oklahoma	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southwestern Electric Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Wheeling Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Avista Corporation	AVA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CenterPoint Energy Houston Electric, LLC	CNP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southern Indiana Gas and Electric Company, Inc.	CNP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Consumers Energy Company	CMS	0.25%	0.26%	0.27%	0.27%	0.29%	0.29%	0.30%	0.30%	0.28%
Virginia Electric and Power Company	D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
South Carolina Electric & Gas Co.	D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DTE Electric Company	DTE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Carolinas, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Florida, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Indiana, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Kentucky, Inc.	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Ohio, Inc.	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Progress, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy Arkansas, Inc.	ETR	0.00%	0.00%	0.00%	0.00%	0.52%	0.53%	0.59%	0.60%	0.28%
Entergy Louisiana, LLC	ETR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy Mississippi, Inc.	ETR	0.00%	0.00%	0.00%	0.00%	0.79%	0.80%	0.81%	0.82%	0.40%
Entergy New Orleans, LLC	ETR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy Texas, Inc.	ETR	1.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.13%
Kansas City Power & Light Company	EVRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kansas Gas and Electric Company	EVRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
KCP&L Greater Missouri Operations Company	EVRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Westar Energy (KPL)	EVRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cleveland Electric Illuminating Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Jersey Central Power & Light Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Metropolitan Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Monongahela Power Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ohio Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pennsylvania Electric Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pennsylvania Power Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Potomac Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Toledo Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
West Penn Power Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Idaho Power Co.	IDA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Florida Power & Light Company	NEE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Gulf Power Company	NEE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NorthWestern Corporation	NWE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Oklahoma Gas and Electric Company	OGE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Otter Tail Corporation	OTTR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Arizona Public Service Company	PNW	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Public Service Company of New Mexico	PNM	0.37%	0.38%	0.38%	0.38%	0.36%	0.37%	0.37%	0.37%	0.37%
Texas-New Mexico Power Company	PNM	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Portland General Electric Company	POR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kentucky Utilities Company	PPL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Louisville Gas and Electric Company	PPL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
PPL Electric Utilities Corporation	PPL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Alabama Power Company	SO	1.66%	1.74%	1.75%	1.87%	1.85%	1.88%	1.94%	2.01%	1.84%
Georgia Power Company	SO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mississippi Power Company	SO	0.00%	0.00%	0.00%	0.00%	1.04%	1.04%	1.05%	0.96%	0.51%
Northern States Power Company - MN	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Northern States Power Company - WI	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Public Service Company of Colorado	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southwestern Public Service Company	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Notes:

[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

Docket No. UE 374
Exhibit PAC/500
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Michael G. Wilding

February 2020

TABLE OF CONTENTS

ATTACHED EXHIBITS

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 Michael G. Wilding. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My title is Director, Net Power Costs and Regulatory Policy.

Q. Briefly describe your education and business experience.

A. I received a Master of Accounting from Weber State University and a Bachelor of Science degree in accounting from Utah State University and am a Certified Public Accountant licensed in the state of Utah. During my tenure at the Company, I have worked on various regulatory projects including general rate cases, the multi-state protocol, and net power cost filings. I have been employed by PacifiCorp since 2014.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the Public Utility Commission of Oregon (Commission), and the public utility commissions in California, Idaho, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

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

A. My testimony describes how net power costs (NPC) are currently forecast, recovered and trued-up by the Company; proposes consolidation of the Transition Adjustment Mechanism (TAM) and Power Cost Adjustment Mechanism (PCAM) filings into a single annual filing, the Annual Power Cost Adjustment (APCA); and proposes changes to the annual power cost true-up to remove the sharing bands, deadbands, and earnings test. Finally, my testimony addresses several drivers supporting these proposed changes.

III. NPC RECOVERY

Q. Please describe how PacifiCorp recovers its Oregon-allocated NPC.

A. In Oregon, PacifiCorp forecasts a level of NPC for the following calendar year (test year) through the TAM. PacifiCorp uses its Generation and Regulation Initiative Decision Tools (GRID) model to forecast NPC for the test year. This forecast level of NPC is recovered through Schedule 201 during the test year. In the year following the test year, PacifiCorp files a PCAM, which is a mechanism that allows for recovery of un-forecasted deviations in NPC. PacifiCorp has never triggered a rate change through the PCAM.

Q. Why are NPC reset annually?

A. In approving annual power cost updates through the TAM, the Commission has recognized that "it is important to update the forecast of power costs included in rates to account for new information, *e.g.,* on expected market prices for electricity and natural gas, and for new…purchase power contracts" and that "[i]f the forecast is not updated each year, then [the utility] will be exposed to more than normal business risk."[1] NPC can vary significantly year-to-year for a variety of reasons, including changes to loads, fuel costs, market prices, and renewable resource availability. This variability makes it difficult to accurately forecast NPC for ratemaking purposes.

[1] *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).

Q. Please briefly describe the TAM.

A. The purpose of the TAM is to capture costs associated with direct access and prevent unwarranted cost shifting between cost of service customers and customers that elect direct access service.[2] Significantly, the TAM also sets PacifiCorp's Oregon-allocated NPC for the upcoming year.[3] The direct access transition adjustments are calculated by comparing the value of energy used to serve direct access loads with the cost of service rate under the customers' specific energy-only tariff. The Commission adopted an annual NPC update to ensure that both the value of freed-up energy and the cost of service rate are calculated for the same period using the same data. The Commission has articulated the importance of accurate NPC modeling in the TAM:

> PacifiCorp's TAM is an annual filing in which PacifiCorp projects the amount of [NPC] to be reflected in customer rates for the following year, as well as to set transition charges for customers electing to move to direct access. The TAM effectively removes regulatory lag for the company because the forecasts are used to adjust rates. For that reason, the accuracy of the forecasts is of significant importance to setting fair just and reasonable rates. Our goal, therefore, is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year.[4]

Q. Please briefly describe PacifiCorp's PCAM authorized by the Commission.

A. Commission Order 12-493 approved a PCAM to allow PacifiCorp to recover the difference between actual PCAM costs incurred to serve customers and the base PCAM costs established in PacifiCorp's annual TAM filing.[5] PCAM costs include

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[2] *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).
[3] *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).
[4] *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).
[5] *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).

NPC, other revenues, and federal production tax credits (PTC). As the Commission observed when it adopted a PCAM for Portland General Electric Company, the PCAM has been designed so that the utility "will bear normal business risk associated with actual power costs varying from forecast."[6]

Q. Please describe the relationship of the TAM and PCAM.

A. Each year the PCAM compares the NPC collected from Oregon customers in rates set in the TAM to the actual Oregon-allocated NPC. The PCAM variance, however, is subject to an asymmetrical deadband between a $30 million under-collection and a $15 million over-collection, a symmetrical sharing band where the Company absorbs 10 percent of the variance outside the deadband, and finally a symmetrical earnings test where the collection or refund of a PCAM variance is limited to amounts that will bring PacifiCorp to within 100 basis points of the Company's authorized return on equity (ROE). Additionally, the amortization of deferred amounts are capped at six percent of the revenue for the preceding calendar year.

Q. Has the current construct of the TAM and PCAM provided PacifiCorp with a reasonable opportunity to recover its prudently incurred NPC?

A. No. Despite persistent and significant under-recovery of NPC since the implementation of the PCAM, due to the operation of the deadbands, sharing bands, and earnings test, PacifiCorp's rates have never been adjusted as the result of the PCAM. Notably, for the time period of 2014 to 2018, PacifiCorp has under-recovered approximately $77 million of NPC and the only year of

[6] Order No. 07-015 at 17-19.

over-recovery was 2016.[7] As further discussed in the testimony of Mr. Frank Graves, this systematic under-recovery of prudently incurred NPC occurs because of the restrictions of the PCAM and the inability to forecast certain system balancing costs in the TAM.

Q. If the TAM and PCAM are prohibitive to the recovery of prudently incurred NPC, why did PacifiCorp over-recover NPC in 2016?

A. As explained in the testimony of Mr. Graves, despite an over-recovery of total Oregon-allocated NPC, PacifiCorp still experienced system balancing costs not captured in the TAM.[8] In 2016, PacifiCorp's hydro generation was within one percent of the TAM forecast and its owned wind generation was more than four percent above the TAM forecast. In addition, natural gas market prices and energy prices were very low relative to other years. The actual average cost of natural gas generation was approximately 15 percent lower than forecast in the TAM and the average price of market purchases was approximately 37 percent lower than forecast in the TAM. These items combined to outweigh the under-collection of the system balancing costs described by Mr. Graves.

Q. How is the energy landscape changing compared to when the PCAM was approved in 2012?

A. As discussed further in the testimony of Mr. Graves, since 2012, the energy landscape in the West has continued to evolve, with an increasing number of states adopting clean energy standards (including Senate Bill (SB) 1547 in Oregon), the development

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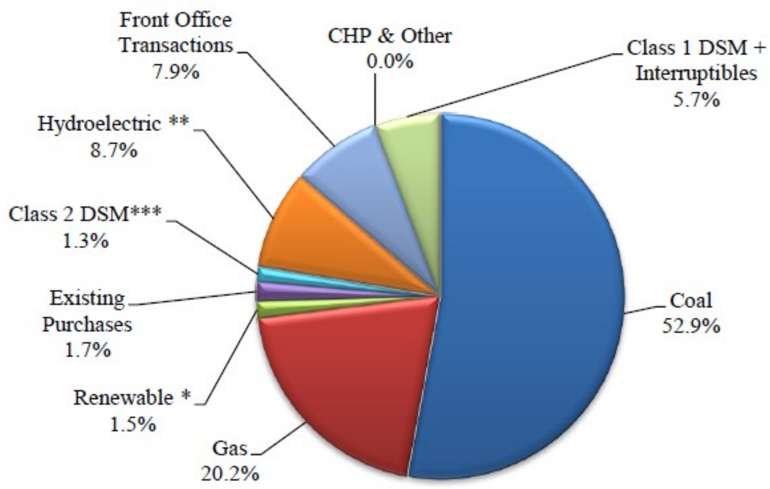
[7] For purposes of this testimony, 2016 Jim Bridger coal costs have been adjusted to remove certain unusual costs that would not be included in a TAM.
[8] PAC/600, Graves/17-20.

of the energy imbalance market (EIM) and, more recently, region-wide discussions regarding regional resource adequacy and possible creation of a day-ahead energy market. In response to shifting energy policy in the West, along with changes in federal energy policy such as the extension of federal PTCs, and changing market conditions, PacifiCorp is in the process of transitioning its existing generation fleet and building new transmission to accommodate additional renewable generation capacity, with approximately 1,500 megawatts of new wind capacity and a 140-mile, 500 kilovolts transmission line coming online by the end of 2020.

Q. How has PacifiCorp's resource mix changed as a result of this shifting energy landscape?

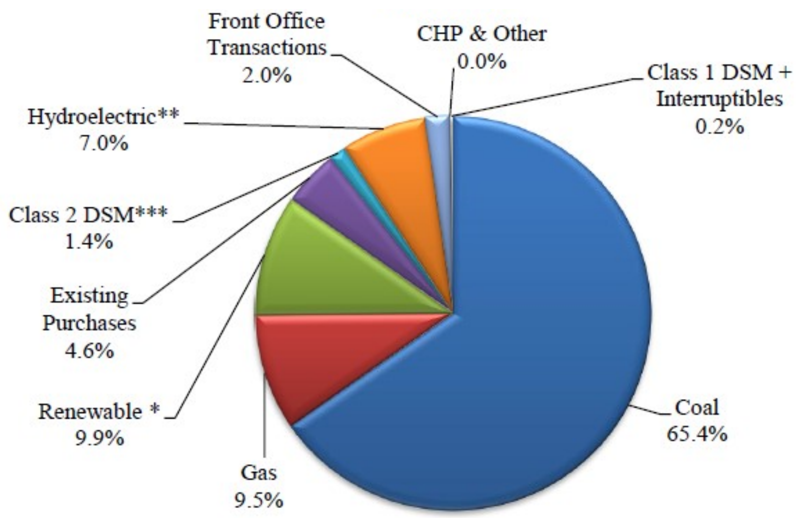
A. PacifiCorp continues to adapt to, among other things, changing market conditions and increasing demand from customers for specific types of generating resources. This adaptation is shown in the figures below. In PacifiCorp's 2013 Integrated Resource Plan (IRP), the energy and capacity resource mix was heavily dependent on thermal resources. Only 1.5 percent of PacifiCorp's resource capacity came from renewable resources. In contrast, the 2019 IRP projects 33 percent of PacifiCorp's resource capacity in 2021 to come from renewable resources. Similarly, PacifiCorp's resource capacity mix from coal-fired generation will drop from 53 percent to 31 percent during this same timeframe.

1 **FIGURE 1[9]**
PACIFICORP'S 2013 CAPACITY MIX



* Renewable resources include wind, solar and geothermal. Wind capacity is reported as the peak load contribution.
** Hydroelectric resouces include owned, qualifying facilities and contract purchases.
*** The contribution of Class 2 DSM represents incremental acquisition of DSM resources over the planning period.

2 **FIGURE 2[10]**
PACIFICORP'S 2013 ENERGY MIX



* Renewable resources include wind, solar and geothermal.
** Hydroelectric resouces include owned, qualifying facilities and contract purchases.
*** The contribution of Class 2 DSM represents incremental acquisition of DSM resources over the planning period.

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[9] *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).
[10] *Id.* at 230.

FIGURE 3[11]
PACIFICORP'S 2019 CAPACITY MIX

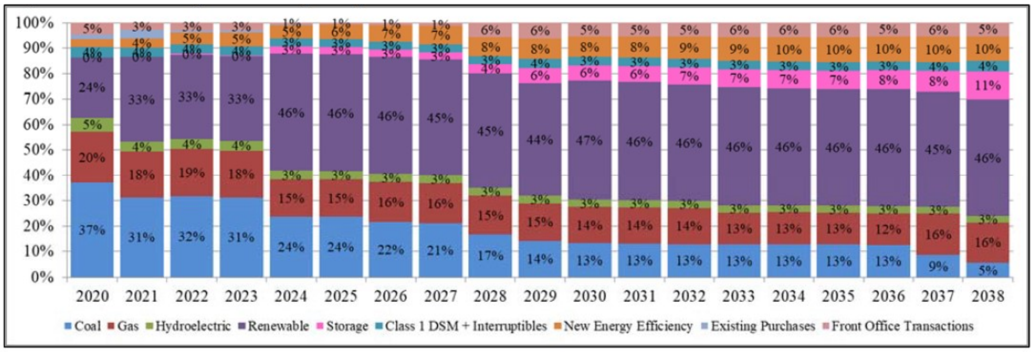
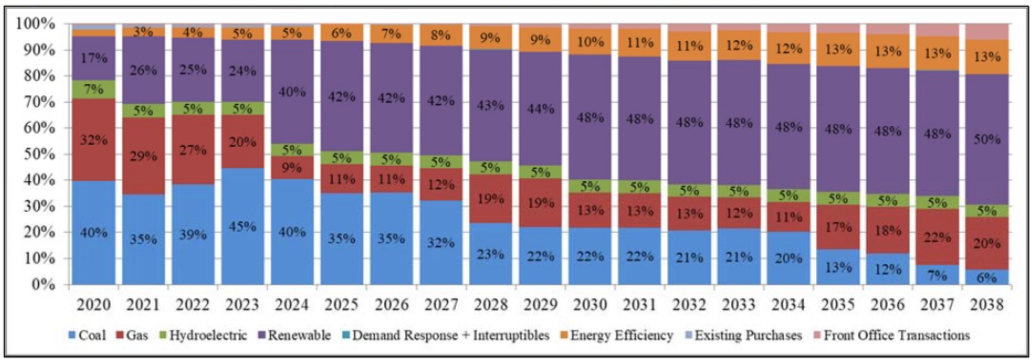


FIGURE 4[12]
PACIFICORP'S 2019 ENERGY MIX



By 2030, PacifiCorp currently projects that 45 percent of system capacity will come from renewable resources and coal will supply only 13 percent of system capacity.

Q. How has this change in resource mix affected the Company's NPC?

A. The capital costs and the operations and maintenance (O&M) expense of renewable resources owned by PacifiCorp, in this case wind resources, are included in base rates, while the variable energy costs are included in NPC. Importantly, the renewable resource provides zero-fuel-cost energy, or even negative-cost energy when PTCs and other benefits are considered. This means that PacifiCorp's

[11] *In the matter of PacifiCorp, dba Pacific Power, 2019 Integrated Resource Plan*, Docket No. LC 70, PacifiCorp's 2019 Integrated Resource Plan at 257 (Oct. 18, 2019).
[12] *Id.*

customers benefit when they receive the entire energy output of the owned wind resources and those resources are the last to be curtailed when there is an energy surplus.

If the renewable resource is a qualifying facility (QF) or another purchased power agreement (PPA), then the purchase price of the contract is included in NPC. PacifiCorp is required to purchase the entire energy output offered from a QF, with no curtailment rights. Project developers also generally require PacifiCorp to purchase the entire energy output of a facility under non-QF PPAs.

As renewable resources are weather dependent and do not have the same flexibility as a thermal resource, PacifiCorp has limited ability to plan for and control their availability and output. As explained by Mr. Graves, it is impossible to accurately forecast the output of these renewable resources, specifically wind resources, on an hourly basis for an entire year, which makes it increasingly difficult to accurately forecast NPC.

IV. PACIFICORP'S PROPOSAL

Q. What is PacifiCorp's proposal for forecasting and recovering NPC?

A. PacifiCorp proposes to combine the TAM and PCAM into a single NPC mechanism—the APCA—that would be filed on May 15 of every year. The APCA would replace the TAM that is typically filed on April 1 and the PCAM that is filed on May 15. As part of the APCA, PacifiCorp would file a forecast for NPC for the following year (test year), and request an adjustment or true-up for power costs of the previous year. In addition, PacifiCorp proposes to remove the deadbands, sharing bands, and earnings test from the annual true-up of power costs. Using the TAM

Guidelines, PacifiCorp created a set of APCA Guidelines to provide governance for parties. The APCA Guidelines are attached as Exhibit PAC/501. The first APCA would be filed on May 15, 2021, with a forecast for the calendar year 2022 and a true-up of calendar year 2020.

Q. What is the purpose of the APCA?

A. The APCA would provide PacifiCorp with the opportunity to recover its prudently incurred NPC and set the transition adjustments for customers choosing direct access.

Q. Has the Commission expressed an interest in combining PacifiCorp's TAM and PCAM?

A. Yes. In PacifiCorp's latest PCAM, the Commission stated "we consider that integrating the PCAM testimony in PacifiCorp's annual TAM filing may be useful by ensuring the most current information on actual power costs informs the TAM forecast."[13] While PacifiCorp's proposal is a shift from how Oregon has traditionally considered power costs cases, there are compelling reasons for making this change.

Q. Would combining the TAM and PCAM allow the most current information to be incorporated in the NPC forecast as suggested by the Commission?

A. Yes. Currently the TAM forecast uses a base period of actual data for the period ending in June of the prior year, which is nearly a year old when the TAM is filed on April 1. By combining the TAM and PCAM and filing on May 15, the most current information for the period ending in December of the year before the APCA is filed can be used for the NPC forecast.

[13] *In the matter of PacifiCorp, dba Pacific Power's 2018 Power Cost Adjustment Mechanism*, Docket No. UE 361, Order No. 19-415 at 4 (Nov. 25, 2019).

Q. If the TAM is filed at a later date, what parts of the NPC forecast will use more current information?

A. If the TAM were filed on May 15 of every year, most of the NPC forecast data inputs will use more current information. Forecasted wholesales sales and purchased power will include the most recent six months of data. Market prices for electricity and natural gas will use the Official Forward Price Curve (OFPC) at the end of March of the filing year, instead of from December of the prior year. Hydro, thermal and renewable resources generation characteristics will be based on more recent information as well. Fuel expense would also use the most recent information from the Company's fuel contracts.

Q. Does the Company's proposal to file a consolidated APCA on May 15 of each year impact the timeline for Commission review of forecast NPC?

A. Yes. The Company's proposal shortens the Commission review timeline by approximately six weeks. In addition to proposing a consolidated APCA, PacifiCorp also proposes to remove the deadbands, sharing bands, and earnings test from the annual power cost true-up. One effect of these proposed changes to the annual power cost true-up is to invite robust Commission and stakeholder review of the Company's operations as they relate to NPC. Given that no rate changes have ever been proposed in the PCAM as the result of the operation of deadbands, sharing bands, and the earnings test, the Company observes that the PCAM is generally non-contested—in fact, every one of PacifiCorp's PCAMs has been settled. In contrast, the TAM has been fully litigated a number of times with intensive Commission and stakeholder engagement and review of the modeling methodology used to produce the forecast.

The structure of the PCAM—which disfavors any rate change—skews stakeholder resources towards the TAM.

By modifying the PCAM structure to make it more likely that rate changes will occur to account for variations between forecast and actual NPC, PacifiCorp anticipates that stakeholder interest in the PCAM proceeding will increase and stakeholder interest adjudicating modeling methodology will decrease. Indeed, in states where PacifiCorp does not reset base NPC on an annual basis, the annual true-up mechanism has provided a filing for stakeholders to review and audit PacifiCorp's operations as the NPC recovery is based on actual incurred costs versus a forecast.

Additionally, the APCA would have naturally resolved the complex 2020 TAM regarding the new renewable generation coming online in 2020. Stakeholders and the Company came up with innovative but complicated procedures to match the costs and benefits of this new renewable generation. Under the APCA, customers would have automatically received the actual benefits of the new renewable resources, eliminating the need for multiple rate changes in the 2020 TAM.

Q. Will the Company's proposed changes to the annual power cost true-up make the forecast modeling methodology of the TAM irrelevant?

A. No. The modeling methodology used to forecast base NPC in the TAM will continue to be important to the Commission and stakeholders because it is also used to determine the transition adjustment for direct access customers. The Commission has emphasized the need for accurate NPC forecasting to prevent unwarranted cost-shifting caused by direct access.[14] But, as discussed in the testimony of Mr. Graves,

[14] *See, e.g.,* Order No. 05-1050 at 21.

there are major drivers in NPC variances that are both difficult, if not impossible, to accurately forecast and that are not within the control of the Company. Removing the deadbands, sharing bands, and earnings test from the annual power cost true-up puts the focus of inquiry on the prudence of the Company's actions relative to activities it can control (e.g., shifting from accuracy of predicting wind generation to the prudence of how the Company responds in situations when wind generation does not materialize).

Q. Is the APCA in the public interest?

A. Yes. Under the proposed APCA, customers would only pay the actual cost, subject to a prudence review, of the NPC provided to them, no more and no less.

Q. Does PacifiCorp have proposed guidelines describing in detail how this mechanism would function?

A. Yes. As mentioned earlier in my testimony, Exhibit PAC/501 provides guidelines for an APCA proceeding. These guidelines incorporate many elements and procedures that are required in PacifiCorp's TAM and PCAM proceedings.

Q. Besides the filing date, what are the major changes PacifiCorp is proposing to make to the NPC forecast compared to the TAM?

A. Generally speaking, the NPC forecast in the APCA would be very similar to the TAM, with a change that allows PacifiCorp the ability to update coal costs at the Jim Bridger plant as part of the rebuttal update.

Q. Have these changes been reflected in the proposed guidelines attached to your testimony?

A. Yes. I have reflected these edits to the proposed guidelines attached as Exhibit PAC/501, which also include additional provisions that have been incorporated into the TAM guidelines since their adoption in 2009.

Q. Does the APCA make any changes to the direct access transition adjustments?

A. No. The transition adjustments will be calculated the same way and under the same timeframe as they are currently done in the TAM.[15]

Q. What are the major changes PacifiCorp is proposing to make to the NPC true-up compared to the PCAM?

A. PacifiCorp is only requesting the NPC true-up not include any deadbands, sharing bands, or earnings test.

Q. Are there any exceptions to these PCAM changes?

A. Yes. In the 2020 TAM, PacifiCorp agreed to use specified wind capacity factors through a 2025 test year.[16] In the spirit of this agreement, PacifiCorp will continue to use the specified wind capacity factors agreed to in the 2020 TAM and any variation in PTCs would not be subject to the annual true-up through 2025 if the deadbands, sharing bands, and earnings tests are removed.

[15] Consistent with ORS 757.609 and OAR 860-038-0275, final transition adjustment pricing must be available to non-residential customers by November 15 every year. This time-frame is necessary given the annual November/December election window for direct access customers.

[16] *In the matter of PacifiCorp, dba Pacific Power 2020 Transition Adjustment Mechanism,* Docket No. UE 356, Order No. 19-351 at Appendix A, 8-9 (Oct. 30, 2019).

Q. Is combining the TAM and PCAM into a single filing essential to PacifiCorp's request?

A. No. The proposal to combine the TAM and PCAM was born from the Commission's inquiry in the most recent PCAM order.[17] If the Commission determines, however, that the TAM and PCAM be combined into a single proceeding, it is essential the deadbands, sharing bands, and earnings test be removed from the NPC true-up to ensure that the TAM can proceed on a procedural schedule that allows for setting the transition adjustments in time for the direct access election window. If the Commission determines it prefers separate TAM and PCAM proceedings, the Company requests the Commission approve the updated TAM guidelines to allow for Jim Bridger coal to be updated on rebuttal. Additionally, the Company requests the Commission approve changes to the PCAM to eliminate the deadbands, sharing bands, and earnings test.

V. UPCOMING SHIFTS IN THE ALLOCATION OF NET POWER COSTS

Q. What other changes is PacifiCorp anticipating to its generation portfolio?

A. In addition to the changes outlined in the 2019 IRP preferred portfolio, PacifiCorp is anticipating that each state within its service territory could have unique generation portfolios beginning in 2024. The PacifiCorp 2020 Inter-Jurisdictional Allocation Protocol (2020 Protocol)[18] outlines the path to state-specific generation portfolios to comply with state-specific energy policies, such as SB 1547, and establishes certain

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[17] *See In the matter of PacifiCorp, dba Pacific Power 2018 Power Cost Adjustment Mechanism*, Docket No. UE 361, Order No. 19-415 at 4 (Nov. 25, 2019).

[18] *In the matter of PacifiCorp, dba Pacific Power, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approval and Inter-Jurisdictional Cost Allocation Protocol,* Docket No. UM 1050, Order No. 20-024 at 8 (Jan. 23, 2020).

"Framework Issues" that need to be resolved. In addition to providing a path for states to have unique resource portfolios, it is important to maintain the benefits of system dispatch and optimization as much as practicable.

Q. Is PacifiCorp currently working on a new approach to allocating NPC?

A. Yes. This is one of the Framework Issues in the 2020 Protocol. This is a complex issue requiring the Company to develop a new system to track the real-time costs of generation based on each state's allocated share of each resource. Additionally, the Company is planning on further discussions within the Framework Issues workgroup within the multi-state process relative to the usage and implementation of a new system for ratemaking purposes beginning in 2024. The new system is referred to as the Nodal Pricing Model (NPM).

Q. Please describe the NPM.

A. The NPM is a tool designed to track NPC by generation resources and by state under an inter-jurisdictional cost allocation that will no longer dynamically allocate costs among states based on their respective loads. Instead, generation-related costs will follow the assignment of those resources. To develop the NPM, PacifiCorp is working with the California Independent System Operator (CAISO) who, acting as a third party vendor, will produce optimal unit commitment and hourly energy schedules for supply resources in the PacifiCorp balancing authority areas using the CAISO day-ahead market model. PacifiCorp will use the NPM to track costs and benefits associated with the different resource portfolios used to serve PacifiCorp's load in each state for ratemaking purposes.

Q. Please describe conceptually how the NPM will work.

A. The NPC associated with each generating resource will be assigned to states based on each generating resource's assignment. For example, if a state is assigned 25 percent of a natural gas plant, then it is also assigned 25 percent of the fuel costs associated with that resource, regardless of load. Each resource also receives a credit based on the locational marginal price (LMP) for its generation, which is also assigned to each state per its assignment of each generating resource. The assigned NPC, less the credit received, will be the states' total NPC.

Q. Please explain the credit received by each generating resource in more detail.

A. Each generating resource will receive a credit for the energy it generates or the reserves it provides, and each state's load will be charged a load aggregated point (LAP) price.[19] The total credits the generating resources receive will equal the dollar amount that each state's load is charged. This facilitates a transfer of energy between states at a fair price based on the LMP and preserves the benefits of a system dispatch and optimization.

Q. How will unique generation portfolios increase the difficulty of forecasting NPC?

A. Moving from a dynamic inter-jurisdictional cost allocation to a static inter-jurisdictional cost allocation for generation costs will increase the pressure to have every NPC line item accurately forecast to mitigate the risk of potential swings in state-allocated NPC. For example, if the total natural gas fuel expense forecast in the TAM matched the actual total natural gas fuel expense, the fuel expense at each plant could still be slightly different between the forecast and actuals. Under a dynamic

[19] The LAP price is the weighted average LMP at each load point or node within the LAP.

allocation where each state is allocated a proportional share of each plant's fuel expense, the allocations are not affected and there is zero difference between the forecast and actual state-allocated total natural gas fuel expense. However, under a static allocation, the differences in each plant will flow through to the states, causing some states' actual natural gas expense to be higher than forecast and others to be lower. Unless there is complete recovery of actual NPC, this could result in an over or under allocation of fuel costs to Oregon.

Additionally, as explained by Mr. Graves, production cost models are generally too smooth and because of their perfect foresight, these models do not capture uncertainty. As described above, the NPM facilitates a transfer of energy between states at a fair price by charging loads the LAP price and crediting generators for their production at the LMP. PacifiCorp is currently working towards a production cost model capable of forecasting LMPs to use in the NPM. However, because of the smoothness of any model it is likely that the forecast LMPs and actual LMPs will be different causing differences between state-allocated NPC.

Q. Do the issues identified above still exist if PacifiCorp joins a regional market such as the Extended Day-Ahead Market (EDAM)?

A. Yes. In fact, participating in a regional day-ahead market would make it even more difficult to recover NPC by only using a forecast such as the TAM. A regional market would optimize the entire footprint of the market and PacifiCorp would be limited to publicly available information in an attempt to model the market optimization. In addition, the market dynamics themselves would be more complicated with LMPs than they have been in the past and would potentially make outcomes more volatile and forecasting more difficult. Despite this complexity, participating in the market will be important as it will provide benefits that will potentially reduce total NPC. As explained by Mr. Graves, most participants of an organized market are able to recover 100 percent of their prudently incurred NPC through some sort of pass-through mechanism.

Q. Does the current construct effectively allow PacifiCorp to meet customer's needs in a changing energy landscape?

A. No. As explained in more detail by Mr. Graves, as PacifiCorp's generation portfolio includes increasing levels of renewable resources, it becomes increasingly difficult to consistently recover prudently incurred NPC using the TAM and PCAM. Additionally, as PacifiCorp's energy landscape evolves to state-specific generation portfolios that provide states a path for compliance with their energy policies, additional forecast error risk is introduced and the ability to fully recover actual NPC is even more important.

VI. CONCLUSION

Q. Please summarize your recommendation to the Commission.

A. I recommend the Commission approve modifications to the design of the PCAM to remove the sharing bands, dead bands, and earnings test, and approve consolidation of the TAM and PCAM into a single proceeding—the APCA.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/501
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Proposed Annual Power Cost Adjustment Guidelines

February 2020

PACIFICORP
OREGON ANNUAL POWER COST ADJUSTMENT (APCA)
General Guidelines

PacifiCorp's Annual Power Cost Adjustment (APCA) 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. Additionally, the APCA includes a true-up of actual NPC from the previous year to the forecast NPC of that year.

When filed on a stand-alone basis, the APCA is intended to be narrower and more streamlined than when the APCA is filed in or processed concurrently with a general rate case. In any case, parties to the APCA 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 APCA 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 APCA 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 APCA, that the APCA should be eliminated or revised.

A. NPC

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, on May 15, the Company will make an Initial Filing to recover any variance between the forecast and actual NPC for the previous calendar year, forecast NPC for the following calendar year, and set direct access transition adjustments for the following calendar year. In any future APCA filings after UE 374, 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 APCA 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 APCA 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 May 15th of the year of the stand-alone APCA filing, or (b) the Company built the resource and it was used and useful prior to May 15th of the year of the stand-alone APCA filing.

3. The prudence of the decision to build or acquire the resource may be determined in the stand-alone APCA 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 APCA filing by April 15th of the year of the stand-alone APCA 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 APCA filing, the Company will also update other revenues that are tracked in FERC Account 456 - Other Electric Revenue. When an APCA is filed in or processed concurrently with a general rate case, this element may be included in the APCA or the general rate case. Additionally, the APCA 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 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 the Initial Filing, the Company will reflect forecast changes in Other Revenue for items that have a direct relation to NPC, for which a revenue baseline has been established in rates in Docket UE 375 or subsequent rate case.

7. In any APCA 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.

8. 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 APCA or general rate proceeding. The Parties preserve their right to challenge the confidential designation of any documents or data.

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 APCA an ongoing protective order which will continue to be effective in future APCA proceedings.

11. The Company's Initial Filing will include direct testimony covering any unusual expenses incurred over the course of the previous calendar year and identify and discuss any large deviations of actual NPC from forecasted NPC. The Company will also provide with its workpapers a differential worksheet the produces actual minus base power costs for each separate cost category in the recovery of the previous year's NPC on a gross costs and per megawatt-hour (MWh) unit basis.

12. 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.

    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);

b. Post indicative transition adjustments for Schedules 294 and 295;

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 GRID. 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.

ii. Schedule 200 Supply Service rate design will be non-bypassable to direct access customers and will not be subtracted in the calculation of the Transition Adjustment. In addition, the Schedule 201 rate design as proposed by the Company will be allowed to go into effect and will be bypassable to direct access customers. The rate design for proposed Schedule 200 applicable to delivery service Schedules 30, 47, and 48 will be changed from its present energy only cents per kilowatt-hour (kWh) rate design to a two-part rate design which includes a demand charge equal to $1.00 per billing kilowatt (as defined in the respective tariffs) plus a cents per kWh energy charge.

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 filings as specified in Attachment A.

4. If a Party objects to any aspect of the Final Update, the Party reserves all of its procedural rights to seek review of the controverted issue.

5. The Parties agree to meet and review whether to recommend to the Commission an extension in length for the election window for PacifiCorp's multi-year direct access option beginning in November 2009.

E. Actual NPC True-Up

The ACPA true-up is calculated on a monthly basis. Actual APCA costs are compared to base APCA cost on a per-unit basis. APCA costs are established in the APCA forecast and include NPC, Other Revenues, and PTCs. Any differences in the system per-unit cost are multiplied by the actual megawatt hours of Oregon retail sales in that month to determine Oregon's share of any differential. The calculation uses the following formula:

$$(APCAC_a \div Load_a) - (APCAC_b \div Load_b) = \text{System APCA Unit Cost Differential}$$

$$\text{System APCA Unit Cost Differential} \times Load_o + (SR_a - SR_b) = \text{APCA Differential}$$

Where:

$APCAC_a$	= Total Company Adjusted Actual NPC (Excluding Situs Resources) plus other costs/benefits reflected in Oregon APCA Forecast
$Load_a$	= Actual System Retail Load
$APCAC_b$	= Total Company Base NPC (Excluding Situs Resources) adjusted for Direct Access plus other costs/benefits reflected in Oregon Forecast
$Load_b$	= Base System Retail Load

$Load_o$	= Actual Oregon Retail Load
SR_a	= Actual Situs Resource Value
SR_b	= Forecasted Situs Resource Value

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 APCA filed in or processed concurrently with a general rate case after UE 207, the APCA rate design test year will be the general rate case rate design test year. In a stand-alone APCA, the APCA rate design test year will be the forecast test year during which the Schedule 201 rates will be effective.

3. In any future APCA filed in or processed concurrently with a general rate case after UE 374, 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.

   In any future stand-alone APCA, 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. APCA Filings Made in or Processed Concurrently with a General Rate Case

1. If the Company files a general rate case prior to May 15 in a given year, then the Company may file the APCA before May 15. If the Company chooses not to file a APCA prior to May 15, then it must file on May 15. If the APCA is filed on a stand-alone basis, it will be filed no later than May 15. In order to accommodate the direct access window that begins November 15, the APCA may be bifurcated from the full rate case in order to allow for a Commission decision by November 1. Bifurcation of the APCA does not alter any provision below.

2. When an APCA 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 APCA filing made before the APCA is again filed in or processed concurrently with a general rate case.

3. When an APCA is filed in or processed concurrently with a general rate case, the APCA will be subject to rebuttal and final updates identifies 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 APCA proceedings or in future general rate cases.

Attachment A
APCA Workpapers and Supporting Documents

Workpapers are defined in OAR 860-001-0480(5) as “documents that show the source, calculations, and details supporting the testimony and other exhibits submitted.” In an APCA proceeding, the term “workpapers” means the documents used to develop the final inputs to GRID and the final modeling in GRID. The data relied upon to support the cost details in the filing may include contracts, emails, white papers, studies, PacifiCorp computer programs, Excel spreadsheets, Word documents or pdf, and text files.

If the Commission adopts new minimum filing requirements, rules or guidelines for net power cost filings, these will replace the requirements set forth in this document. Additionally, if the APCA is eliminated, the APCA Design Guidelines to which this document is attached are materially changed, or the Parties otherwise agree, the requirements set forth in this document will cease to be operative. In cases where systems change or are replaced in the future, PacifiCorp will continue to provide substantially the same information as provided in data request responses in PacifiCorp’s 2009 TAM (UE 199), the relevant citations to which are listed below, as long as these filing requirements remain operative.

The Parties agree to continue the current practice of providing all discovery response answers, workpapers, including any other documents produced pursuant to this agreement via email (for non-confidential documents) and overnight mail. The GRID model and its inputs, however, will be produced on the day of the filing electronically to the Parties in accordance with the terms of the stipulation in docket UE 199.

Parties will expeditiously work to rectify any workpaper deficiencies without requiring other Parties to submit follow-up data requests.

In cases where the Company has relied upon documents or workpapers it considers to be “highly confidential” it will notify the Parties of such, and, if the amount of data considered highly confidential is limited, it will redact the highly confidential data or otherwise modify the non-confidential workpapers to prevent disclosure of highly confidential material. If the Company has withheld any information on the grounds that the information is “highly confidential,” the Company will request a “highly confidential” protective order or other special handling measures within five days of providing the non-highly confidential material.

A. Initial Filing by Company

For the Initial Filing, PacifiCorp will provide workpapers and supporting documents as described below. All information will be provided electronically and, in the case of Excel spreadsheets, with all cells and formulas intact.

1. Concurrent with the filing:

    a) Workpapers that show the source, calculations and details supporting the testimony and other exhibits. The workpapers will include, at a minimum, copies of the net power cost report in Excel and the net power cost model database. Access to the power cost model will also be provided.

b) Identification of the Four Year Period used to determine outage rates and other input items in the net power cost model.
c) Compilations of actual net power costs produced by PacifiCorp that were referenced in the testimony or exhibits, to the extent that actual power cost results are discussed or cited in the Company's direct testimony or exhibits. *See, e.g.,* ICNU 1.5-1 in UE 199.
d) A list and explanation of all modeling or logic changes or enhancements to the net power cost model that have been implemented since the most recent Oregon APCA or general rate case. This will include a statement of the direction and amount of change in net power costs resulting from each such change and documentation describing each change as well as net power cost model runs and workpapers quantifying the impacts of these changes.

2. Within five business days after the Initial Filing, the Company will deliver to the Parties:

   a) Workpapers showing the computation of the outage rates (planned and unplanned) used in the power cost model. Include all backup data showing each outage (planned or unplanned, etc.) and duration (planned or unplanned) considered in the four-year period, including NERC cause code, type of event, duration, energy lost, etc. *See, e.g.,* ICNU 1.6-1 and 1.6-2 in UE 199.
   b) The heat rate curves for each resource and the spreadsheets showing the derivation of the heat rate curves. *See, e.g.,* ICNU 1.22 in UE 199.
   c) Workpapers and documentation supporting the inputs contained in the "Other Cost" file as of UE 199, used in the power cost model, including all electronic spreadsheets used to compute any of the line items in the file. This includes test year: wheeling expenses modeled in GRID. *See, e.g.,* ICNU 1.28 in UE 199.
   d) Workpapers and documentation supporting the "Energy Cost" file used in the power cost model, including all electronic spreadsheets used to compute any of the line items in the file. *See, e.g.,* ICNU 1.29 in UE 199.
   e) Workpapers and documentation supporting the "Demand" file used in the power cost model including all electronic spreadsheets used to compute any of the line items in the file. *See, e.g.,* ICNU 1.31 in UE 199.

3. As soon as practical after filing, delivered on an as-ready basis, but no later than 15 days after the Initial Filing, the Company will deliver to the Parties:

   a) All documents, workpapers or other information relied upon by the Company in determining the market caps used in the power cost model for the Pro-Forma Period. See, e.g., ICNU 1.2 in UE 199.

b) The current topology maps in the power cost model along with an explanation for all the differences that have been made to the topology since the last APCA or general rate case and an explanation of why the changes were made. Include supporting documentation, such as contracts resulting in changes to the transfer capabilities used in GRID. *See, e.g.,* ICNU 1.3 and 1.68 in UE 199.

c) The date and a copy of the forward price curve, showing monthly heavy load hour and light load hour forward prices, used in creating the Test Year power cost model studies.

d) Documents showing all short-term firm transactions (including short-term firm indexed transactions and swaps) modeled in the test year power cost study, *see, e.g.,* ICNU 1.11, and as long as the Commission retains an adjustment for wholesale trading margin, the backup for the calculation of the trading margin, *see, e.g.* 1.13 and ICNU Supplemental 18.24 in UE 199. In addition, each contract will have a designation as to its purpose (i.e., trading, arbitrage or balancing.)

e) For all power, fuel and transmission related contracts modeled in GRID that were not included in the most recent Oregon APCA or general rate case:
   1. A copy of the contract (in pdf or electronic format, if available).
   2. Any workpapers or other documents used to develop the power cost model input assumptions related to the contract.

f) Regulatory Fuel Budget filing used for the test year and any other workpapers used in developing the power cost model fuel cost inputs.

g) Workpapers and documentation supporting the "Demand Cost" file used in the power cost model, including all electronic spreadsheets used to compute any of the line items in the file. *See, e.g.,* ICNU 1.30 in UE 199.

h) Identification of each instance in which the Company changed any maximum capacities, minimum up or down times or unit minimum capacities for thermal or hydro generators modeled in the power cost model since the last Oregon APCA or general rate case, if applicable.

i) Workpapers explaining the development of each line of load adjustments presented on the Company's power cost model output reports. *See, e.g.,* ICNU 1.53 in UE 199. These include but are not limited to:
   1. DSM (irrigation)
   2. MagCorp Curtailment
   3. Monsanto Curtailment
   4. Station Service

j) Workpapers used to develop inputs for qualifying facility contracts modeled in GRID. *See, e.g.,* ICNU 1.33b in UE 199.

k) A 40-year hydro data set suitable for input into the GRID model applicable to the test year so long as the Company has been required by regulators in proceedings in other states to produce this material, and the Company proposes to change its hydro modeling from the single (Median hydro) scenario filed in the initial filing in UE 207.

l) Data necessary to calculate forced outages using hourly forced outage shaping as adopted by the Commission in Order 15-394.

m) Sample calculations of the transition adjustments for Schedule 30 Secondary and Schedule 48 Primary in Schedule 294, with all supporting documentation.
n) Workpapers for any screens applied to prevent uneconomic commitment and dispatch of resources in the GRID model.
o) Supporting transaction level detail for compilations of actual power costs produced by PacifiCorp that were referenced in the testimony or exhibits, to the extent that actual power costs results are discussed or cited in the Company's direct testimony or exhibits. *See, e.g.* ICNU 1.5-2 in UE 199.
p) Workpapers and all supporting documents underlying the start-up fuel and start-up operations and maintenance costs included in GRID.

B. Response Filing (or Surrebuttal Filing, if applicable) by Staff and Intervenors

Parties filing testimony in response to the Company's Initial Filing (or Rebuttal Filing, if applicable), will provide workpapers and supporting documents as described below.

1. Concurrent with the filing:

a) Workpapers that show the source, calculations and details supporting the testimony and other exhibits. The workpapers will show on an adjustment-by-adjustment basis, the power cost model input file or files used, the back-up to the input files, and the power cost model study reports or documents showing the impact of the adjustment on net power costs as compared to the comparison scenario. The associated power cost model input files will be provided as well.

C. Rebuttal Update Filing (and Sursurrebuttal Filing, if applicable) and Final Updates by Company

For the Rebuttal Update Filing and Final Updates, PacifiCorp will provide workpapers and supporting documents as described below.

1. Concurrent with the filing:

a) Workpapers that show the source, calculations and details supporting the testimony and other exhibits. The workpapers will include the net power costs report on an adjustment-by-adjustment basis. The workpapers will include, at a minimum, electronic copies of the net power cost report and the net power cost model.
b) For any update, adjustment or correction to the power cost model, the Company will include a description of the change and a calculation of the adjustment amount.

2. As soon as practical after filing, but no later than three days after the filing:
    a) To the extent that any of the items in Section A above change, new versions of the supporting documentation and workpapers will be provided.

Access to the updated runs in power cost model via the designated internet access or power cost model input files containing all inputs and output reports associated with the update filings.

D. Other Items

1. The Company will provide information on new contracts or updates to contracts that are executed after the Rebuttal Filing and will be included in the Final Updates as soon as practical after execution. The Company will track the contracts and produce them in groups as their total number or value become material.

2. The Company will provide broker quotes compared to the Company's forward price curve used in the final net power cost update as soon as practical.

~~PACIFIC POWER~~

PACIFICORP
OREGON ~~TRANSITION~~ANNUAL POWER COST ADJUSTMENT ~~MECHANISM (TAM~~(APCA)
~~Agreement of the Parties on~~ General Guidelines

~~Pacific Power's Transition~~PacifiCorp's Annual Power Cost Adjustment ~~Mechanism (TAM~~(APCA) 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. Additionally, the APCA includes a true-up of actual NPC from the previous year to the forecast NPC of that year.

When filed on a stand-alone basis, the ~~TAM~~APCA is intended to be narrower and more streamlined than when the ~~TAM~~APCA is filed in or processed concurrently with a general rate case. In any case, parties to ~~a TAM~~the APCA 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. Parties have not resolved and may address in UE 210, Pacific Power's general rate case, issues including but not limited to whether: (1) changes in methodologies utilized in the calculation of net power costs, such as those used to calculate normalized hydro or forced or planned outage rates or calculation issues resolved by the Commission, will be permitted in stand-alone TAM proceedings; and (2) a stand-alone TAM should include the variable costs of new generation resources if the Company will not recover the fixed costs of the generation resource in the TAM rate effective period.~~ APCA 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~~APCA proceeding. Nothing in ~~this agreement~~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~~APCA, that the ~~TAM~~APCA should be eliminated or revised.

A. NPC

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.

~~A.~~B. Initial Filing – Forecast NPC

Each year, on May 15, the Company will make an Initial Filing to ~~forecast net power costs~~recover any variance between the forecast and actual NPC for the previous calendar year, forecast NPC for the following calendar year, and set direct access transition adjustments for the following calendar year. In any future ~~TAM~~APCA filings after UE ~~207~~374, the Initial Filing will be consistent with the following provisions:

1. At least 30 days prior to the ~~initial filing~~Initial Filing, the Company will provide a pre-filing ~~review to Staff, CUB and ICNU~~notice of ~~any proposed~~substantial changes to the ~~net power cost model (e.g., new version of GRID). For this pre-filing review, the~~ methodologies used to forecast NPC. The Company will include in its APCA 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~~, where practical, of the prior year net power costs~~ of NPC forecast model results with and without the ~~model changes. In a stand-alone TAM~~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 APCA 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 May 15th of the year of the stand-alone APCA filing, or (b) the Company built the resource and it was used and useful prior to May 15th of the year of the stand-alone APCA filing~~, the Company agrees not to include model changes in its forthcoming.~~

~~1.~~3. The prudence of the decision to build or acquire the resource may be determined in the stand-alone APCA 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 APCA filing ~~if Staff, CUB or ICNU~~

~~objects~~by April 15th of the year of the stand-alone APCA filing.

~~2.~~4. The Initial Filing will include updates to all of the ~~net power cost~~NPC components identified in ~~Attachment~~Section A. These costs will be based on the ~~Company's~~Company's most recent official forward price curve, forecast load and allocation factors. In a stand-alone ~~TAM~~APCA filing, the Company will also update ~~the steam~~other revenues ~~associated with Little Mountain steam sales, which~~that are tracked in FERC Account 456 - Other Electric Revenue. When ~~a TAM~~an APCA is filed in or processed concurrently with a general rate case, this element may be included in the ~~TAM~~APCA or the general rate case. ~~Parties have not resolved and may address in PacifiCorp's 2010 TAM, UE 207, whether non-fuel start-up costs may be included in a stand-alone TAM filing.~~Additionally, the APCA forecast will include production tax credits (PTC).

~~1.~~ 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 ~~this Agreement~~these guidelines and: (1) the new contract or contract update is based upon new information of which the Company reasonably became aware after the ~~net power cost~~NPC study for the Initial Filing was completed; or

~~3.~~5. (2) the omission resulted from a mistake that occurred despite the ~~Company's~~Company's reasonable diligence in meeting its 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 UE 207 and any future TAM~~In the Initial Filing, the Company will reflect forecast changes in Other Revenue for items that have a direct relation to NPC, for which a revenue baseline has been established in rates in Docket UE 375 or subsequent rate case.

~~4.~~7. In any APCA 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 ~~fifteen~~15 business days before Staff and Intervenor Direct Testimony is due.

~~5.~~8. The Company will provide access to the ~~net power cost~~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~~APCA or general rate proceeding. The Parties preserve their right to challenge the confidential designation of any documents or data.

~~6.~~9. The Company will provide workpapers and other ~~supp01iing~~supporting documents as specified in Attachment ~~B~~A.

10. The Parties agree to ask the Commission to make the protective order for the next ~~TAM~~APCA an ongoing protective order which will continue to be effective in future ~~TAM~~APCA proceedings.

11. The Company's Initial Filing will include direct testimony covering any unusual expenses incurred over the course of the previous calendar year and identify and discuss any large deviations of actual NPC from forecasted NPC. The Company will also provide with its workpapers a differential worksheet the produces actual minus base power costs for each separate cost category in the recovery of the previous year's NPC on a gross costs and per megawatt-hour (MWh) unit basis.

~~7.~~12. These Guidelines do not limit the ability of other Parties to ~~this Agreement may seek ongoing party status in Pacific Power's TAM proceedings and Pacific Power will support this request.~~propose updates consistent with these Guidelines after the Company's Initial Filing.

~~B.~~C. Rebuttal Update Filing – Forecast NPC

At the time the Company makes its ~~rebuttal filing~~Rebuttal Update Filing, it will include an update to forecast ~~net power costs~~ NPC consistent with the following provisions:

1. The Company will update the following ~~net power cost~~ 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; ~~(b)~~

      ii. coal and natural gas sales, purchases and transportation contracts; ~~and (c)~~

      iii. wheeling contracts~~.~~; and

      iv. coal contracts for mines directly or indirectly owned by the Company.

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. ~~For example, this would permit updates to coal costs under Company contracts with third parties, but would not permit updates to coal costs for mines directly or indirectly owned by the Company.~~

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 ~~co11'ect~~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 ~~B~~A.

~~C.~~D. Final Updates – Forecast NPC

The Company will file ~~final updates~~Final Updates to ~~net power costs~~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 ~~net power costs~~forecast NPC, incorporating the following:

        i. ~~i.~~ Commission-~~-~~ordered adjustments;

        ii. ~~11.~~ Forward Price Curve from within nine days of the filing date;

        iii. ~~111.~~ 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, ~~sh01i~~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);

~~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).~~

b. Post indicative transition adjustments for Schedules 294 and 295;

c. Provide indicative supply service ~~net power cost~~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 ~~net power costs~~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 GRID. 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.

ii. Schedule 200 Supply Service rate design will be non-bypassable to direct access customers and will not be subtracted in the calculation of the Transition Adjustment. In addition, the Schedule 201 rate design as proposed by the Company will be allowed to go into effect and will be bypassable to direct access customers. The rate design for proposed Schedule 200 applicable to delivery service Schedules 30, 47, and 48 will be changed from its present energy only cents per kilowatt-hour (kWh) rate design to a two-part rate design which includes a demand charge equal to $1.00 per billing kilowatt (as defined in the respective tariffs) plus a cents per kWh energy charge.

c. Provide supply service ~~net power cost~~ NPC rates (to be Schedule 201)

3. The Company will provide workpapers and other ~~suppo1iing~~supporting documents for both the indicative and final filings as specified in Attachment ~~B~~A.

4. If a Party objects to any aspect of the Final Update, the Party reserves all of its procedural rights to seek review of the ~~controve1ted~~controverted issue.

5. The Parties agree to meet and review whether to recommend to the Commission an extension in length for the ~~shopping~~election window for ~~PacifiCorp's~~PacifiCorp's multi-year direct access option beginning in November 2009.

E. Actual NPC True-Up

The ACPA true-up is calculated on a monthly basis. Actual APCA costs are compared to base APCA cost on a per-unit basis. APCA costs are established in the APCA forecast and include NPC, Other Revenues, and PTCs. Any differences in the system per-unit cost are multiplied by the actual megawatt hours of Oregon retail sales in that month to determine Oregon's share of any differential. The calculation uses the following formula:

$$(APCAC_a \div Load_a) - (APCAC_b \div Load_b) = \text{System APCA Unit Cost Differential}$$

$$\text{System APCA Unit Cost Differential} \times Load_o + (SR_a - SR_b) = \text{APCA Differential}$$

Where:

$APCAC_a$ = Total Company Adjusted Actual NPC (Excluding Situs Resources) plus other costs/benefits reflected in Oregon APCA Forecast

$Load_a$ = Actual System Retail Load

$APCAC_b$ = Total Company Base NPC (Excluding Situs Resources) adjusted for Direct Access plus other costs/benefits reflected in Oregon Forecast

$Load_b$ = Base System Retail Load

$Load_o$ = Actual Oregon Retail Load

SR_a = Actual Situs Resource Value

SR_b = Forecasted Situs Resource Value

~~D.~~F. Rate Design

1. In the ~~Company's~~Company's current general rate case, proposed ~~net power costs~~NPC

are unbundled from other generation costs. All ~~net power costs~~NPC will be collected through a new Schedule 201, ~~Net~~Annual Power ~~Costs - Transition~~Cost Adjustment ~~Mechanism~~, which will be applied as a rider to Schedule 200. Schedule 200 will continue to collect other generation costs.

2. In any future ~~TAM~~APCA filed in or processed concurrently with a general rate case after UE 207, the ~~TAM~~APCA rate design test year will be the general rate case rate design test year. In a stand~~-~~-alone ~~TAM~~APCA, the ~~TAM~~APCA rate design test year will be the forecast test year during which the Schedule 201 rates will be effective.

~~2. If PacifiCorp has not filed a general rate case within four years of the filing of UE 210, and does not plan to file a rate case by March 1, 2014, the Company will convene technical workshops no later than July 1, 2013 to provide the parties to the "Agreement of the Parties on General Guidelines" with relevant information to allow parties to make a preliminary determination if the then-current rate spread for its TAM rates may be unfair, unjust or unreasonable. If one or more parties to the "Agreement of the Parties on General Guidelines" makes a preliminary determination, by September 1, 2013, that the then current rate spread for its TAM rates may be unfair, unjust or unreasonable, PacifiCorp will file its next application as a TAM filed in or processed concurrently with a general rate case.~~

3. In any future ~~TAM~~APCA filed in or processed concurrently with a general rate case after UE ~~207~~374, proposed Schedule 201 revenues by rate schedule will be determined by spreading the total forecast ~~net power costs~~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.

In any future stand-alone ~~TAM~~APCA, Proposed Schedule 201 revenues by rate schedule will be determined by spreading the total forecast ~~net power costs~~NPC for the test year to the rate schedules based upon each ~~schedule's~~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.

~~E.~~G. ~~TAM~~APCA Filings Made in or Processed Concurrently with a General Rate Case

~~In all future TAM filings after UE 207 in a year in which the~~ If the Company files a general rate case~~, the TAM will be included in or processed concurrently with~~ prior to May 15 in a given year, then the Company may file the ~~general rate case filing. In future filings after UE 207,~~APCA before May 15. If the Company ~~agrees that both filings will be made no later than March 1 to allow for~~chooses not to file a ~~January 1 rate effective date. This commitment will cease if~~APCA prior to May 15, then it must file on May 15. If the ~~TAM is eliminated or there are material changes in these TAM Design Guidelines. If the TAM~~APCA is filed on a stand-alone basis, it will be filed no later than ~~April~~

1. ~~1~~May 15. In order to accommodate the direct access window that begins November 15, the ~~TAM~~APCA may be bifurcated from the full rate case in order to allow for a Commission decision by November 1. Bifurcation of the ~~TAM~~APCA does not alter any provision below.

2. When ~~a TAM~~an APCA 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~~APCA filing made before the ~~TAM~~APCA is again filed in or processed concurrently with a general rate case.

3. When ~~a TAM~~an APCA is filed in or processed concurrently with a general rate case, the ~~TAM~~APCA will be subject to rebuttal and final updates ~~identified~~identifies above and ~~to~~ the agreements on workpapers and other supporting documents ~~specified~~specific in Attachment ~~B~~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 APCA proceedings or in future general rate cases.

REDACTED
Docket No. UE 374
Exhibit PAC/600
Witness: Frank Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Frank Graves

February 2020

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ATTACHED EXHIBITS

PAC Exhibit PAC/601—Resume

PAC Exhibit PAC/602—Review of PCAM Implementation in Other States

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, position and business address.

A. My name is Frank Graves. I am a Principal at The Brattle Group, located in our headquarters office at One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q. Please summarize your education and professional experience.

A. For most of my career spanning over 30 years as a consultant, I have worked in regulatory and financial economics, especially regarding long-range planning for electric and gas utilities, and in litigation matters related to securities litigation and risk management. My education includes an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

In regard to forecasting, utility resource planning, and cost recovery risks, which are central matters in this case, I have extensive experience in system planning with capacity optimization and production cost models, load forecasting, fuel procurement and risk management, and pollution control compliance. Recently, I have focused on evaluating pathways to deep decarbonization of the energy sector, including the impacts of much greater reliance on renewable generation and distributed energy resources. I have developed, evaluated, or used many power system production and resource planning models as well as utility financial projections for revenue requirements and alternative rate design purposes, and I have evaluated financial risk and cost of capital in a wide variety of settings for energy infrastructure and utility investments. I have given expert testimony on financial and regulatory issues before the Federal Energy Regulatory Commission (FERC), many state regulatory commissions (including Oregon, see below), and state and federal courts. My background and qualifications are described in greater detail in the résumé attached as Exhibit PAC/601.

Q. What testimonies have you previously provided in proceedings before the Public Utility Commission of Oregon (Commission) or in regard to PacifiCorp (PacifiCorp or the Company) in any of its other state jurisdictions?

A. I have provided direct and rebuttal testimony on behalf of companies within PacifiCorp's six-state service territory on several occasions in regard to aspects of fuel and purchased power procurement, forecasting, hedging and cost recovery. Going by state, I testified for PacifiCorp in Utah in 2010 and 2011 in docket 09-035-15 on the need for an Energy Cost Adjustment Mechanism (ECAM) and how that related to risk management practices, and in docket 10-035-124 on the prudence of long-term hedges for natural gas and allowing swap costs in the energy balance account. I testified for PacifiCorp in Wyoming in 2012 (docket 20000-405-ER-11) on utility hedging practices and state practices for cost recovery in rebuttal of suggested 50/50 sharing of gains and losses in those positions, and in 2015 (docket 20000-409-ER-15) regarding a day-ahead versus real-time (DA/RT) adjustment to the net power costs (NPC) in rates to correct for intrinsic under-recovery from short-term transactions in the ECAM. In Oregon that same year, I presented direct and reply testimony in docket UE-296 on the costs of balancing the system and the need for DA/RT adjustments.

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

A. My testimony discusses the sources of risk and resulting typical under-recovery in the current Power Cost Adjustment Mechanism (PCAM) for PacifiCorp in Oregon to demonstrate how difficult these variances are to forecast or control. I also explain why these difficulties and resulting downward biases in recovered NPC are likely to increase in the coming years, due to increasing reliance on renewable resources and more participation in regional markets. Accordingly, I recommend that the deadbands and profit collars on sharing those NPC variances be eliminated to better align PacifiCorp's financial risks for recovery of NPC with the very limited level of control over the key drivers of the NPC uncertainty. I also discuss the fuel-cost sharing policies of other states, and the ineffectiveness of the sharing rules currently in place (deadbands, profit collars) on NPC variances to create meaningful or useful incentives for PacifiCorp to manage its fuel and purchase power costs differently.

Q. Please summarize your conclusions.

A. A review of the past several years of NPC forecasts and actual costs shows that there has been a systematic under-recovery of those actuals, accumulating to approximately $77 million on an Oregon-allocated basis between 2014 and 2018. The large variances in Oregon have not been passed on in whole or in any part to customers in Oregon because of the wide deadbands and profit collars on PCAM conditions for sharing them, effectively passing the entirety of the NPC shortfall on to PacifiCorp shareholders.

My review shows that the largest and most persistent component of these shortfalls has been the costs of purchases and sales in the wholesale market(s) to balance the system (e.g., when the renewables produce more or less than expected, or load is different than forecast) and to simply trade economically with other utilities that have their own imbalances or less/more cost-effective units available.[1]

Such trading volume is very large—on the order of a quarter of jurisdictional retail sales—and it involves material benefits to PacifiCorp customers from the savings and efficiency gains. On the other hand, it is extremely difficult to forecast when, where, and at what price or cost these numerous short-term transactions will take place. Indeed, it is not likely that modeling improvements could be made to reduce this problem, leading to substantial actual NPC deviations from planned costs that are in rates.

Even more consequential for NPC and the PCAM, these deviations in costs do not tend to balance out over time from a blend of some over- versus some under-forecasting. Instead, it is more likely that both positive and negative deviations from expected volumes will have net costs, for two reasons. First, because the supply curve for available power is usually increasingly upward sloping at higher loads, the positive deviations in load (actuals greater than forecast) will often have greater incremental costs than the comparable incremental savings from the negative deviations (which occur in a lower cost, flatter portion of the supply curve). That is, the extra power needed when the forecast is low will tend to cost more than was

[1] The DA/RT adjustment is designed to capture certain system balancing costs that are otherwise excluded from the NPC forecast by virtue of the nature of the Generation and Regulation Initiative Decision Tools (GRID) model's perfect foresight, among other reasons, as discussed in prior cases and reiterated below. While the DA/RT adjustment has mitigated, to some extent, the under-forecasting bias resulting from system balancing transactions, it remains an imperfect solution, as demonstrated by the under-recovery that has continued in the years subsequent to implementation of the DA/RT adjustment. Nevertheless, the DA/RT adjustment remains necessary because the NPC forecast is more accurate with it than without.

expected if the actual volume had matched expectations, while reduced power needs that do not have to be purchased or generated may not save much relative to the forecast costs. Second, it is possible that lower than expected load volumes will directly involve losses if the planned volumes (of electricity sales or their generation fuel costs) were hedged and those hedges have to be closed out at a lower price than was expected.

Importantly, these under-recovery biases occur in all time frames, e.g., within the day for hourly transactions, even if the day as a whole had actual demands that matched the forecast. This is particularly significant for renewables which can only be forecast for ratemaking on the basis of long-term weather patterns that are not accurate for short-term operations. For instance, if the wind blows more than was expected, and the output is under a long-term contract priced above market energy prices, the excess adds considerable unplanned NPC.

These recurring under-recoveries are not the result of bad forecasting or bad operational management. The planning methods and tools that PacifiCorp uses are consistent with good industry practice, as well as their assumptions and data sources for key inputs. To the contrary, these under-recoveries are a byproduct of the beneficial and cost-saving move to greater reliance on renewables and on market transactions.[2] Because those costs are so difficult to forecast, and they do not occur or arise in the "base case" scenario used to set rates (only in the variances from those projections), they are inadvertently not recognized and are excluded from base rates. A prudently incurred cost is simply missing from the allowed costs in the revenue requirement.

Such difficulties and the associated under-recovery are likely to increase in the future, because of the changes to PacifiCorp's generation portfolio outlined in its 2019 Integrated Resource Plan (IRP), the near-term renewable acquisitions included in the 2019 IRP action plan and because much of the rest of the Western Electricity Coordinating Council (WECC) is similarly transitioning away from coal-fired generation resources towards increased renewable capacity, and the pending move to nodal and state-specific energy pricing by PacifiCorp. These changes will increase forecasting difficulties, will likely make PacifiCorp's supply variances more correlated with other companies across larger areas (hence more impactful on spot energy prices)—at the same time as they will make market participation more beneficial and important.

[2] A significant part of the forecasting problem here is inability to know the short-term deviations from average or typical renewable output. The average (or total output) over moderate time frames, such as a month, can be known in advance with reasonable accuracy, as I show later in Confidential Figure 7. Such average amounts can then be hedged to dampen a material portion of cost risk. However, a year in advance, the rate-setting time in the TAM, it is not possible to have any meaningful insight into intra-month, intra-day or intra-hourly even shorter period renewable output variances, nor into what the corresponding variance and correlation in hourly or shorter term energy prices will be when those wind and solar variances occur. It is possible to do beneficial short-term hedging throughout the year, to further reduce the extent of error exposure, but always subject to volume uncertainty within the hedged period. For instance, it may be that next week's weather forecast features lots of rain, so it is unlikely the solar generation will produce much power. This was not knowable at the beginning of the year, but can be acted upon a week or so in advance to hedge those conditions. Even then, it will not be possible to hedge much or perhaps any of the intra-week variance at that time.

These forecasting and variance-costing problems are widespread throughout the electric industry and so can be considered normal business risk, but what is not normal is for the utility to bear so much and such asymmetric cost-recovery exposure to them. The vast majority of other states have full flow-through cost recovery of NPC-type costs, without deadbands or sharing limitations. This reflects an appreciation that there is no efficiency improvement from putting a utility at risk for largely uncontrollable and unforecastable costs. Therefore, I recommend eliminating the deadbands, sharing bands, and earnings test and allowing full NPC recovery for PacifiCorp, subject to prudence review.

Q. How is your testimony organized?

A. In Section II, I review the terms of the current PCAM established in Oregon, including a summary of the types of costs it includes, how and when the costs are measured, and the risk-sharing between PacifiCorp's ratepayers and shareholders for the deviations between forecast and actual NPC. Then, in Section III, I summarize PacifiCorp's experience in Oregon for the recovery of NPC, and I identify several of the key drivers of the deviations between forecast NPC used to set retail rates versus the actual NPC over the last several years. I explain in Section IV why these cost deviations tend to create under-recovery, rather than to balance out as errors that can go either way. I also explain why they are intrinsically very difficult to capture in forecasts and how they are outside of PacifiCorp's control, together making PCAM variances a poor candidate as an incentive mechanism for improved utility operations. In Section V, I explain the appropriateness of PacifiCorp's proposed modifications to the PCAM approach in Oregon. Finally, in Section VI of my testimony, I provide an overview of how some of the other utility jurisdictions treat similar types of risks associated with cost recovery of NPC-type costs.

II. CURRENT PCAM IN OREGON

Q. What are the components of PCAM costs?

A. As described in Mr. Michael G. Wilding's testimony, the PCAM is a balancing or true-up mechanism with risk-sharing that allows the possibility for PacifiCorp to recover a portion of large differences between the actual PCAM costs incurred to serve its customers and the forecast "base" PCAM costs established during annual transition adjustment mechanism (TAM) filings. The historical PCAM costs include NPC plus other costs/revenues not captured in NPC, such as: ongoing costs associated with PacifiCorp's participation in the Western Energy Imbalance Market (EIM), Production Tax Credits (PTC), and other revenues collected under PacifiCorp's Schedule 205.[3]

Q. How does PacifiCorp estimate the PCAM costs that are reflected in retail rates?

A. The base PCAM costs used to set customer rates in Oregon are estimated in annual TAM filings. PacifiCorp forecasts its system-wide NPC using the GRID model, which simulates the operations of the Company's owned and contracted generators for its entire fleet across all its state jurisdictions, along with market purchases and sales for the future test year based on contracts and expected spot trades for economics and balancing. The NPC is calculated as the sum of fuel costs, wholesale power purchase costs, and wheeling costs, net of wholesale sales revenues. The model results are adjusted to increase the accuracy of system balancing transactions

[3] I understand that the non-NPC EIM costs will be removed from the PCAM process beginning with the 2021 general rate case, and instead will be part of base rates.

(DA/RT adjustment) and to reflect incremental EIM benefits. PTCs and other revenues are estimated outside of the GRID model, included as a part of the TAM filings.

A share of the total Company-wide costs is allocated to Oregon based on Oregon customer's proportion and pattern of the forecast load. Oregon uses a one-year forward projected test year for those calculations (while other PacifiCorp states use somewhat different time frames). The TAM-estimated average cost per kilowatt hour (kWh) for NPC becomes the basis for rates. Any deviation from those forecast prices and the corresponding unit costs in actual NPC (plus a few smaller additional factors, shown below) multiplied by actual retail sales volumes becomes a variance that is subject to possible partial recovery or refund under the risk-sharing terms of the PCAM.

Q. Can you provide a breakdown of the key components of the PCAM costs in recent years?

A. Yes, Figure 1 summarizes the actual and forecast Company-wide PCAM costs that PacifiCorp incurred during 2014-2018, compiled based on the data from Oregon TAM and PCAM filings. As shown, the NPC accounts for the vast majority of the PCAM costs and the resulting unit cost differentials, which will be the focus of my testimony.

Figure 1: Annual Company-Wide PCAM Costs for 2014-2018

	2014	2015	2016	2017	2018
Total Company Adjusted Actual NPC	$1,603	$1,542	$1,447	$1,528	$1,595
Actual Allocated PTC	–	–	–	($89)	($68)
Actual EIM Costs	–	$6	$5	$5	$3
Actual Other Revenues	–	($24)	($16)	($10)	($11)
Total PCAM Adjusted Actual Costs ($million)	**$1,603**	**$1,524**	**$1,437**	**$1,433**	**$1,519**
Actual System Retail Load (MWh)	54,999,277	54,589,759	54,258,193	55,194,054	55,041,477
Actual PCAM Costs ($/MWh)	**$29.15**	**$27.91**	**$26.48**	**$25.97**	**$27.60**
Total Company Adjusted Base NPC	$1,449	$1,466	$1,514	$1,526	$1,474
Base Allocated PTC	–	–	–	($88)	($67)
Base EIM Costs	–	$7	5	$4	$4
Base Other Revenues	–	($24)	(15)	($11)	($12)
Total PCAM Base Costs ($million)	**$1,449**	**$1,448**	**$1,503**	**$1,431**	**$1,400**
Base System Retail Load (MWh)	54,938,054	55,032,984	56,126,562	55,640,607	54,038,127
Base PCAM Costs ($/MWh)	**$26.37**	**$26.32**	**$26.78**	**$25.73**	**$25.90**
System PCAM Unit Cost Differential ($/MWh)	**$2.78**	**$1.59**	**($0.30)**	**$0.25**	**$1.70**
NPC Differential ($/MWh)	*$2.78*	*$1.60*	*($0.30)*	*$0.25*	*$1.71*
Oregon Retail Load (MWh)	12,958,736	12,862,461	12,868,974	13,200,282	12,867,233
Oregon Annual PCAM Differential ($million)	**$36**	**$20**	**($4)**	**$3**	**$22**

Note:
[1] 2016 Adjusted Actual NPC excludes the recovery and abandonment costs for the Joy longwall mining equipment.

In this figure, a positive differential in the shaded row indicates that the actual unit costs of the actual load were greater per megawatt-hour (MWh) than the forecasted unit costs in rates, causing under-recovery. This occurred in every one of the past five years, except a small negative differential in 2016.

Q. How is the difference between the PCAM costs in retail rates and the actual PCAM costs treated for cost recovery under the current PCAM risk-sharing approach?

A. PCAM balances are calculated based on monthly Company-wide per-unit differentials between actual PCAM and base PCAM unit costs, both multiplied by the actual retail load in Oregon. Thus, errors in forecasting volumes do not directly affect the PCAM variances, though those errors may help explain the differences in forecast unit costs that do determine the amount eligible for risk-sharing. Those amounts are subject to four kinds of filters before being recoverable as described in Order 12-493.[4] *First*, for a given year, any difference within an asymmetrical deadband range of -$15 million over-recovery and +$30 million under-recovery are simply absorbed by PacifiCorp, i.e. not shared. *Second*, amounts above or below the deadband limits are eligible to be shared 90 percent by customers and 10 percent kept by PacifiCorp. However, the *third* filter is that this sharing only occurs to the extent that PacifiCorp's return on equity (ROE) without sharing is more than +/-100 basis points (bp) profits collar away from the authorized ROE. If the variance does not pass these thresholds, PacifiCorp gets no recovery from or gives no refund to customers. PacifiCorp may only recover to within 100 bp of its authorized ROE. And *fourth*, the amortization of deferred amounts under the PCAM in a given year is capped at 6 percent of PacifiCorp's revenues for the previous year.

Q. What is your understanding of why these filters have been adopted by the Commission?

A. It is my understanding that these filters have been based on the PCAM adopted for Portland General Electric Company, and they are "designed so that [the utility] will bear normal business risk associated with actual power costs varying from forecast."[5] I would note, however, that the risk-sharing under the PCAM design is quite

[4] *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).
[5] *In the matter of Portland General Electric Co. Request for a General Rate Revision*, Docket No. UE 180, Order No. 07-015 (Jan. 12, 2007).

asymmetric, with much more potential for Company under-recovery from unexpected losses than for over-recovery from unexpected gains. Thus, even if realized costs tended to vary symmetrically around the forecast used to set rates, i.e., even if there was no long term average forecasting error, the Company would usually end up losing money. This problem is made worse by the fact that even a good forecast will tend to omit the balancing costs (as I explain below). Having such a built-in loss expectation is not normal business risk in the utility industry.

Q. Has the implementation of the current PCAM approach so far resulted in PacifiCorp's Oregon customers bearing some of the PCAM cost deviation?

A. No. Since the beginning of the implementation of the current PCAM approach in Oregon, all of the cost deviations have failed to pass the filters and thus have been absorbed by PacifiCorp in all years. Cumulatively, since 2014, these have resulted in approximately $77 million of unrecovered costs in Oregon equivalent to about 65 basis points per year of shortfall in earned ROE. Importantly, this has not been due to one or two occasional bad years with large losses offset by some years with moderate gains or over-recoveries. In fact, and notably, even unusual events that have adversely affected PacifiCorp operations, such as the Enbridge pipeline rupture in October 2018, have not triggered the PCAM, even though allowing adjustments for major unforeseen events was something the PCAM was designed to accomplish.[6] Instead, actual annual PCAM costs have almost always exceeded the PCAM costs

[6] *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493, at 13 (Dec. 20, 2012) ("any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility").

recovered in rates in the past several years, except for a small over-recovery in 2016.[7] I explain below why this persistent under-recovery is not a coincidence, nor is it related to bad forecasting or system cost management. It reflects the inherently underestimated costs of using the market to balance the system combined with the biased (asymmetric) design of the PCAM.

III. HISTORICAL NPC UNDER-RECOVERY IN OREGON

Q. Please summarize how PacifiCorp's estimate of system-wide NPC deviated from actual NPCs over the last five years.

A. In the five years spanning 2014-2018, Company-wide actual NPC exceeded the one-year ahead forecast in every year except 2016. My analysis indicates that this is largely due to a downward bias in forecasting NPC unit costs relative to actual unit costs because of modeling and informational limitations, market dynamics (all trading companies tending to have similar, concurrent and even aggravating problems relative to their forecasts), the upward and nonlinear shape of the market supply curve for power, and increasing reliance on renewables, especially wind. There is no reason to expect that these problems are going to abate in the future; to the contrary, they may become worse.

I will focus on the patterns and causes for the Company-wide unitized ($/MWh of retail load) NPC deviation metric for the remainder of my testimony, for the following reason. As noted briefly above, the Company-wide unitized ($/MWh) NPC deviation metric is used in the Oregon PCAM determination as a multiplier to the actual retail load in Oregon. Specifically, the NPC charged to Oregon customers

[7] My understanding is that the small over-recovery in 2016 is after extraordinary costs are adjusted out for the Jim Bridger coal costs. All my analysis includes the 2016 adjusted actual NPC.

in rates is the forecast of Company-wide NPC divided by forecast of Company-wide retail load, while the NPC collected from customers is that forecast and authorized rate multiplied by the actual retail load in Oregon. The actual unitized and Company-wide NPC incurred by PacifiCorp is the actual Company-wide NPC divided by actual Company-wide retail load. Hence, the sign of this unitized NPC deviation metric (forecast for rates minus actual unit costs) for the Company as a whole determines whether PacifiCorp under-recovers NPC. This difference in unit costs is multiplied by the actual retail sales volume to set the amounts eligible for recovery, if they exceed the deadbands and profit collars in Oregon. For this reason, it is more important to examine the factors that influence the unitized NPC deviation metric in $/MWh of retail load.

Q. What have been the key components of NPC deviations as indicated by your analysis?

A. The NPC mainly consists of fuel costs, wheeling costs, and net purchase costs (wholesale market sales minus market purchases). Though all of these can have variances, the net purchase costs are the primary driver of NPC deviations in most of the past five years.

Fuel costs like gas and coal prices to PacifiCorp's own generation can contribute to NPC variances. For instance, the volume of their actual generation could be exactly as was forecasted, but the prices for fuel could have been different than was expected and used to set rates. Alternatively, the forecasted fuel costs could be accurate but the utilization of the plants different than was expected. In that case, depending on load, it is likely that the costs or availability of some other types of supply resources (wind, market purchases) are also different. The third and more likely possibility is that both fuel prices and generation volumes will depart from forecast, and in general this will tend to have partly offsetting influences on NPC for fossil generation.

For instance, if actual gas prices are higher than expected, the usage of the gas units will tend to fall, so the overall gas cost share of NPC will be a variance-dampened blend of higher unit costs but smaller volumes (and vice versa if gas costs are lower than expected). In fact, actual gas prices generally fell below forecasts for most of the past few years, and are recently relatively stable, so they have become less of a driver for NPC under-recovery in recent years. Moreover, gas price can be hedged to help eliminate the unit cost risk. Coal price variances are similarly two-sided with possible increases or decreases in cost pushing volumes burned in the other direction. Additionally, coal prices are generally more stable than gas prices, so coal fuel costs do not contribute significantly to NPC under-recovery either.

In contrast to somewhat predictable generation usage, especially from baseload plants, short-term purchases and sales in the wholesale market(s) can be very unstable. There, deviations in volumes and price do not necessarily have offsetting effects. For instance, if loads are higher than expected, a utility may need to buy more power and buy it at a higher price. For PacifiCorp, adverse price variances (transacting at worse costs than forecast) for net purchases (i.e., as explained below, often for both purchases and sales) have occurred in every one of the past five years.

Market-purchased volumes and the prices at which they occur are also quite sensitive to the time pattern and total quantity of generation from renewable resources, which of course are not controllable or readily predicted, except over moderately long term averages. Thus, even with the annual average performance of these technologies fairly well known and possibly hedged, there is a great deal of volatility and complexity to this component of NPC over shorter time horizons.

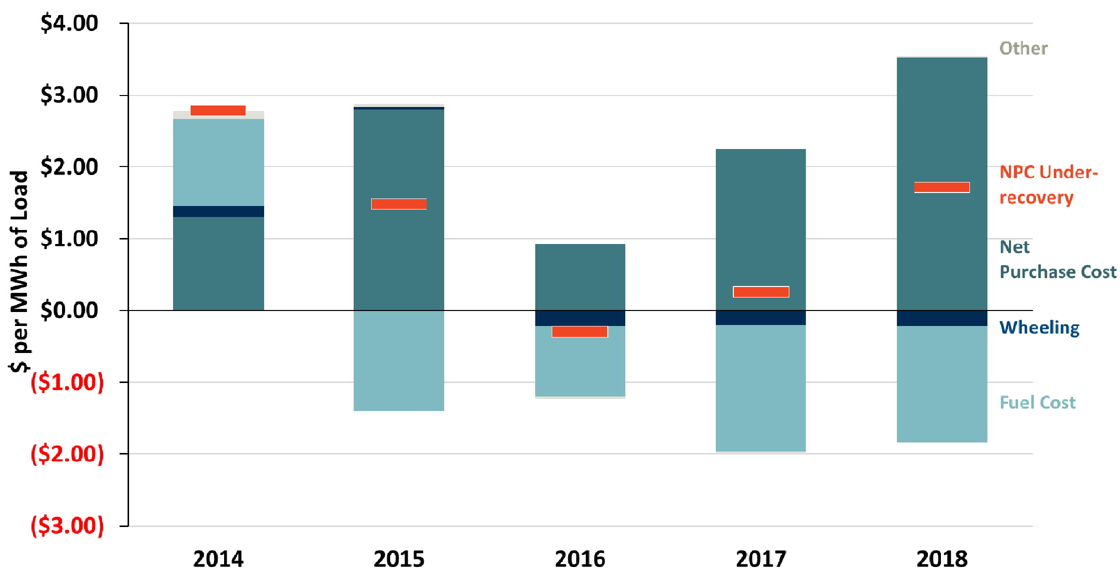
Q. Can you demonstrate these relative shares of influence on NPC variances graphically?

A. Yes, Figure 2 below is a breakdown of the shares of unit cost variance between forecast and actual NPC shown as annual bar charts with stacked layers for the main components. A positive value indicates the actual cost is higher than forecast for that component, thus contributing to the under-recovery in that particular year. Likewise, a component's negative value means that it helps to lower the NPC under-recovery for that year. Of the three main components, net purchase cost was the largest component for 2014-2018, followed by fuel cost and wheeling charges. Fuel cost variance is positive for 2014, though it flipped back to the negative range in the following four years. This is in part driven by large swings in gas prices and gas consumption level during this period. For example, in 2017, both the gas consumption level and the gas prices were lower than forecast, resulting in over-recovery of gas costs.

In addition to being the largest component, net purchase cost remained positive (under-recovered) across the five years in question. As seen in Figure 2, the sign and size of this net purchase cost deficit resulted in an overall shortfall (positive

Net NPC under-recovery), as seen by the red line within the bars, for all years except for 2016, which involved a slight gain.[8] Note however that even when both wheeling and fuel cost deviations were negative in some years, PacifiCorp incurred a NPC under-recovery due to its persistently large positive variance. I decompose this pattern further below to show why it is inherent in NPC.

Figure 2: Composition of NPC Under-recovery for PacifiCorp in Oregon



Notes:
[1] Calculated based on PacifiCorp's PCAM data from 2014 - 2018.
[2] "Other" refers to generating expenses from wind and solar owned by PacifiCorp.

Q. Why do the actual net purchase costs (the subset of NPC shown by the dark teal portions of bars above) exceed the forecasts during all of the years from 2014-2018?

A. Transaction price deviations determine whether actual NPC exceed forecast costs, and the actual volume acts as a multiplier of the difference. Unpredictable natural

[8] The testimony of Mr. Wilding explains why 2016 had a slightly favorable variance, which involved the fact that there were very low gas prices and strong hydro output that year. It is noteworthy that even in a year with such favorable average cost conditions, there was barely any NPC variance (small over-collection), and the under-recovery component from net purchases was still quite positive.

events coupled with complex physical interactions among the participants of the western power grid make it tremendously challenging, if not impossible, for the Company to predict or control the prices at which it buys or sells power other than what is under strict contract. However, as seen in Figure 3, there is naturally a lot of volume of such spot and balancing sales purchases, because of imprecise matching between their supply portfolio and the realized load, similar problems facing other utilities, and the resulting economic opportunities to trade. Note, for instance, that the gross sum (not the net, offsetting sum) of the two is around 25 percent of retail sales. Since each can contribute to NPC, it is this gross sum, not their net, which is most indicative of the scale of the problem. Most of these volumes will be unplanned as to when, where, and at what price they will actually occur at the time of base-rate setting, even if they are fully expected and normal at roughly those levels in the forecast.

Figure 3: PacifiCorp's Short-Term Firm Purchases and Sales

	2014	2015	2016	2017	2018
Short-Term Firm Purchases (MWh)	2,252,456	4,670,988	4,653,654	6,398,082	5,880,090
Percent of Net Retail Load	*4%*	*9%*	*9%*	*12%*	*11%*
Short-Term Firm Sales (MWh)	8,557,501	7,619,541	6,018,797	6,651,663	7,765,501
Percent of Net Retail Load	*16%*	*14%*	*11%*	*12%*	*14%*

For example, if the PacifiCorp service territory experiences an unexpectedly warmer-than-average summer month, demand for electricity will tend to spike upwards for PacifiCorp and for other similarly affected utilities (possibly quite a substantial portion of the WECC). In order to meet this unplanned load increase, PacifiCorp would have to rely on either its more expensive generation assets (the ones not yet being used for planned load levels) or purchase from the market. To the extent that neighboring systems are experiencing similar conditions, market spot prices will be much higher than they would normally be. The supply shortfall may be further exacerbated if other resources that the Company typically relies on generate less than expected—say wind turbines stop operating because of little to no wind (as sometimes happens during heat waves). Consequently, the Company would have to secure even more power than the load increase at a much higher price, which in turn drives up the net purchase costs.

Q. Have you evaluated the key drivers of NPC under-recovery over the last five years to see if a pattern of losses on both under- and over-forecasting (i.e. nearly all unexpected balancing) is evident?

A. Yes, by reviewing the annual and monthly variances in unit costs in relation to net load that is subject to unplanned generation or purchases, I find that the magnitude of the NPC under-recovery has been higher when the actual net load exceeded the forecast, and also when the variances were very small or even negative (actual below forecast)

Net load is a metric designed to identify what supply is needed from dispatchable generation and market purchases (or sales). It is the system load less all wind and hydropower generation on the system. This includes not only resources that PacifiCorp owns, but also all other wind and hydropower resources that it uses that are under long-term contracts, such as qualifying facilities (QF). The net load metric also factors in long-term firm sales and purchases, which are contractual obligations that PacifiCorp has to meet, by subtracting long-term firm purchases and adding long-term firm sales. This definition serves to separate the portion of PacifiCorp's load served by must-take, must-sell, and zero short-run marginal cost (but not necessarily total cost) resources from the remaining load on its more discretionary, dispatchable resources and short-term market purchases, i.e. on the resources that are adjusted to respond to any unplanned requirements (as well as serving a portion of the planned needs).

Additionally, I analyzed how much the forecast for expected net load deviated from the actual net load, both on a monthly and annual basis. If the net load variance is positive for a particular year, the system experiences higher-than-expected net load, resulting in PacifiCorp having to secure more power from dispatchable resources and market purchases than anticipated for that year. As I explained above, power in these instances would have to come from the Company's more expensive generation sources, or from additional purchases.

As seen in Confidential Figure 4, net load variance was positive in 2014, 2015, and 2018, meaning the actual volume exceeded the forecast. Because of the economic dynamics that I explain above, NPC under-recovery was also among the highest for these three years. Vice versa, a negative net load variance indicates that PacifiCorp relied less on its marginal units and market purchases, leading to a lower NPC under-recovery as was the case in 2016 and 2017. In absolute terms, the net load variance is largest in 2016, when forecast net load exceeded the actual by 1.7 million MWh. As a result, 2016 was the only year that PacifiCorp experienced NPC over-recovery.

Confidential Figure 4: Oregon Under-recovery and Related Factors

[redacted]

Notes:
[1] Calculated based on PacifiCorp's PCAM data from 2014 – 2018.
[2] $/MWh values are calculated by dividing under-recovery by total actual retail load of PacifiCorp's system. Retail load is the net system load after taking transmission and distribution losses into account.
[3] Net load variance reflects net system load plus long-term firm sale, subtracting long-term firm purchase and PacifiCorp's own wind and hydro generation. PacifiCorp does not own any solar generation.

The relationship between NPC under-recovery and net load variance is more prominent when shown on a monthly basis. Confidential Figure 5 shows that there is a positive correlation between monthly NPC under-recovery and monthly net load variances for 2014-2018. That is, NPC under-recovery tends to be positive and increasing when actual net load exceeds forecast. Note that the trend line crosses the Y-axis at [redacted], meaning that even when PacifiCorp has accurately forecast its net monthly load, the Company still tends to experience a monthly under-recovery of [redacted].

Confidential Figure 5: 2014-2018 Monthly Average NPC Under-recovery and Company-Wide Net Load Variance

[redacted]

Note:
[1] Calculated based on PacifiCorp's PCAM data from 2014 – 2018.

Q. Why does the magnitude of monthly NPC under-recovery increase at higher levels of net load forecast deviations?

A. Historical data suggests that this is likely due to positive correlation between net load forecast deviations and power price forecast deviations. As shown in Confidential Figure 6 below, actual hub prices at each of the major trading hubs that PacifiCorp uses for purchases and sales tend to exceed forecasts when the actual net load exceed forecast. More specifically, spot prices routinely deviated from the forward market curves at Four Corners, Palo Verde, and Mid-Columbia, three hubs where PacifiCorp historically transacted the most volume. For instance, the difference between actual spot price and forecast price for Mid-Columbia was as high as [redacted] (as in February 2014).

Confidential Figure 6: Monthly Average Hub Price Forecast Variance versus Company-Wide Net Load Variance

[redacted]

Note:
[1] Calculated based on PacifiCorp's electricity hub data from 2014 – 2018. Prices are for flat hours.

This positive correlation means that when PacifiCorp's actual net load exceeds forecast, the Company also tends to experience higher-than-forecast prices for short-term market purchases, increasing the NPC more than proportionally. In contrast, when PacifiCorp's actual net load is less than forecast, actual hub prices do not deviate as much from forecasts. Accordingly, PacifiCorp's sales revenues decrease relative to its forecasts. Therefore, forecast errors in PacifiCorp's net load has an asymmetric impact on NPC deviations as I explain further below.

If the net load volume, which is system load + long term firm sales less (long-term firm purchases + PacifiCorp's wind generation + PacifiCorp's hydro generation), is as forecast, PacifiCorp tends to run its own units at their expected or hedged costs unless the market opportunity to trade is better, which can go both ways.

But if net load volume is higher than forecast for PacifiCorp, it means 1) PacifiCorp has to move further up its own dispatch ladder than was forecast (at higher unit costs per MWh) or purchase more from the market or sell less to the market, and 2) it is likely that the rest of the market is facing similar imbalances, e.g. if it is a hot summer or poor hydro or poor wind conditions. Thus the market price for purchases will also be higher, possibly in a rapidly increasing way as demands push into the high-priced portion of the regional supply curves. Thus, you may have to buy more or sell less at higher prices, for a large adverse NPC variance.

Conversely, if the volume of net load is lower, a utility can move down the supply curve but mostly in the flatter part of the curve (for not much savings compared to moving the other way). If a utility had hedged positions for the expected load, it could sell the excess back to the market, but now likely at a loss to the originally hedged price that was based on higher net demand expectations. Thus a utility is likely to only save a bit or even lose on the adjustment.

Therefore, for both over or under net load forecasts, the error tends to be corrected at a loss.

Q. Does the type of forecasting error and under-recovery that you describe occur at every time scale?

A. Yes. It does occur at every time scale, and sometimes with more variability at shorter intervals, e.g. hourly, where a lot of balancing occurs, and where this is an especially acute issue for wind supply. This component of net load volume can be forecast fairly accurately (or at least usefully) on average over a long time frame (a year or perhaps season), but within those periods may often occur unexpectedly at very different times than planned (e.g., low on-peak day or on-peak hour relative to past patterns of wind), resulting in the same kind of intraday, adverse NPC variances from balancing wind as were shown at the monthly scale for net load. And again, this can occur even if there is no longer-term forecast error for total wind volumes (e.g., over the whole day, month or year).

We can already infer this problem from the above figure by recalling that the fitted trend line crossed the Y-axis at a positive value, i.e. an NPC under-recovery, even though there is no net volume variance at that point. Why is this? It is because the X-axis is measuring average net load error over a whole month. This can be zero, even though there are substantial net load variances (positive and negative) in every day and every hour of that month. Each of those shorter variances will tend to have the same asymmetry of cost as described above, whereby the costs tend to be higher than expected on balancing purchases, and less sensitive (less reduced) on the unforeseen sales or avoided generation.

Q. How does the intermittency of renewable generation influence this shorter term variance problem?

A. It is quite a strong influence. For example, Confidential Figure 7 shows that in 2017 actual hourly wind generation from PacifiCorp's owned and contracted resources deviated from forecast by [redacted] percent (using the absolute hourly deviations), even though on an annual basis, the actual wind generation deviated from forecast by only [redacted] percent. 2018 had similar patterns, with absolute hourly deviations averaging at [redacted] percent versus an annual deviation at only [redacted] percent.[9]

Confidential Figure 7: 2017 Hourly, Monthly, and Annual Wind Generation Deviation

[redacted]

[9] This graphically confirms that the average long-term renewable generation can be meaningfully hedged, but there will be lots of adjustment transactions within the year, some of which can be hedged for blocks of time within the year (though after the TAM forecast) but many not.

Q. Are there other drivers of NPC under-recovery that you have not addressed?

A. Yes. For example in 2014, there were two other adverse surprises in that year that contributed to NPC under-recovery. First, power prices at major trading hubs exceeded the forecasts by about $5/MWh in part due to actual gas prices exceeding forecasts by roughly $1/MMBtu. The higher power prices and gas prices made both the purchases and gas generation more expensive than projections, hence resulting in higher NPC than forecast. Second, PacifiCorp's purchases of third-party wind generation through purchased power agreements (PPAs) from both QFs and non-QFs, exceeded the forecast by about 10 percent. This might seem like good news because it means that fewer market purchases or lower dispatch of higher marginal cost resources are needed. However, the PPA prices of the third-party wind can negate this benefit, if those turn out to be higher than the market energy price at the time of the over-supply variances. This appears to have been the case: The volume-weighted average price paid under these wind PPAs was about $60/MWh, which was roughly double the actual market power prices for energy in that year. Thus PacifiCorp paid more for wind PPAs this year than expected, at costs likely above its own resources' marginal costs or market energy prices.[10] Any such above-market prices for the more-than expected wind output contributed to the NPC under-recovery. (Note that owned wind does not have this problem, because its short-run operating costs are zero, so any increased generation is a source of immediate savings).

[10] This gap is largely because the wind contracts generally recover those resources' fixed costs through variable rates, while the market prices involved in balancing do not generally capture fixed costs from marginal generating facilities.

Q. How does expected wind output enter into the NPC projections that PacifiCorp uses to set rates?

A. It is very difficult if not impossible to forecast when and how much wind will occur, at least not within a forward test year.[11] As a result, PacifiCorp uses a flat average of historical annual wind conditions (at each site) for total output, shaped by the time pattern in the most recent past year of actual output in order to project generation from its wind plants (or it uses the developer's projections if the plant has less than four years of history). This is a reasonable way of projecting those patterns, capturing both the steadiness of the long-term wind patterns and the need to recognize that it typically has a complex (but unstable) seasonal and diurnal pattern. Of course this projection will not match actual realized production patterns, sometimes over-estimating and sometimes under. How that affects NPC depends on whether it occurs for a wind plant owned by PacifiCorp versus under contract for the output at a fixed price per MWh. Positive variances (unexpectedly greater generation) from owned plants will tend to displace fuel use or market purchases, reducing NPC, while such overproduction from a third-party wind resource under a PPA could cause an NPC increase from paying the contract price, if that price is above PacifiCorp's marginal cost.

Note that even if there is exactly the predicted amount of wind over a moderate horizon (a year, or even a day), there can and will be NPC variances arising from what times within that day (or month, etc.) the wind blows and where (because

[11] It is increasingly possible to gain useful, albeit still quite imprecise, forecasts of wind for a day ahead, which helps with unit commitment, but this is not within a horizon that can improve annual forecasting for TAM purposes.

the time of day market prices avoided or incurred are quite volatile). This problem was shown above in Confidential Figure 7 to be extremely common on a daily basis. Thus, wind-based supply, or any intermittent weather-sensitive renewable form of generation, creates an intrinsic NPC variance problem even when it is forecast accurately on average.

This may contribute more NPC variances and under-recovery in the future, as more wind is added to the PacifiCorp fleet and more, older fossil units are retired. Solar power, for which PacifiCorp is planning a significant increase over the next few years, may be slightly more forecast-able, because long-term weather patterns (e.g., annual precipitation) for solar are becoming somewhat predictable by meteorologists albeit still very imprecise. To my knowledge, wind is less amenable to that improvement. The next section describes the increase in planned or required renewables for PacifiCorp and across WECC.

IV. PACIFICORP'S LACK OF CONTROL OVER THE KEY UNCERTAINTIES THAT DRIVE NPC UNDER-RECOVERY

Q. You have explained how forecast errors in either direction induce unplanned net purchases and sales that are likely to create NPC increases. Could PacifiCorp mitigate this problem with better forecasting, or hedging, or changes in operations?

A. No, it is doubtful that much can be done to improve the situation with those adjustments. First, my impression is that the PacifiCorp forecasting methods for these elements of NPC are in keeping with good business practices throughout the industry. While the search for modeling improvements is a good idea, 1) the models and inputs PacifiCorp is using are in keeping with industry standards and are being carefully applied, 2) I am not aware of a model that is capable of capturing the wide variety of unforeseen, stochastic (random) influences that will affect the ultimate NPC, and 3) even if such a model were available, it would not be possible to forecast with any confidence or accuracy the parameters for the random noise from uncontrollable factors that should be overlaid on it to project the coming year. That is, you could perhaps calculate a premium for an assumed level of variance (e.g. based on history), but you would not get a better forecast of what will actually happen.

Likewise, hedging will not help much if at all for the purchased power part of the problem, because the main difficulty is knowing the relevant volumes. Most commercially available hedges are for price protection of a given volume, allowing a utility or producer to hedge specific volumes for specific times. Thus, annual average output can be hedged, but not so much the costs of deviating from that average. The times when there will be an unplanned outage of a generation unit, or there will be more or less wind than in the past from a wind farm, or similar changes on other systems with which PacifiCorp trades, are intrinsically unknowable. Even options, which can be used conditionally, have fixed volumes and periods of allowable exercise. Hedges mostly help the volumes that you can reliably expect. Much of the NPC problem comes from the volumes you cannot plan at least as of the TAM rate-setting time period, except to know in general that they will happen.

Q. Please describe how and why the modeling tools and techniques are limited in ability to work around these problems, such that it would lead you to expect the actual NPC to routinely exceed PacifiCorp's forecasts.

A. Based on my review of the methodology and key assumptions in PacifiCorp's modeling tool GRID to forecast NPC, I conclude that the GRID modeling approach and assumptions include some built-in features (many common to similar models used throughout the industry) that tend to result in under-estimates of the NPC, including the following:

- First, and most insurmountably, system simulation tools like GRID optimize mathematical projections of efficient operations and market transactions under perfect foresight of system conditions and prices, without considering the effects of market uncertainties that create additional unit commitment and dispatch costs, and reduce market participants' ability to find and execute the most profitable transactions. That is not to say that the perfect foresight includes what will actually happen, but as far as the model is concerned, the conditions you project are the only and exact ones that will occur, and then it finds the best way to deal with that. You can run it for different conditions, e.g. higher loads, and perhaps average the two results, but even the alternative scenarios will be perfectly optimized to the parameters of the scenario.
- To be most plausible and useful as an expected cost projection, simulations typically assume "normal" weather, load, hydro generation, without considering the asymmetric impact of deviations from these average conditions. Simulations do not reflect non-standard, challenging and erratic system conditions, such as

transmission outages, fuel supply disruptions (e.g., Aliso Canyon impacts), or extreme weather conditions, such as heat waves, extended droughts, or polar vortexes etc. that can drastically increase power costs and prices. Again, a few such deviant scenarios can be tested, but there are countless perturbations of what they could look like.

- Simulations do not capture inefficiency of fixed-size bilateral trading blocks. Most of PacifiCorp's monthly and day-ahead transactions are executed in blocks (e.g., 16 hour blocks at 25 megawatts (MW) increments), and they are far less flexible and less profitable than the hourly transactions made available in the model.
- Long-term wind and solar forecasts are unable to predict variations within the upcoming year—unlike hydro, which to some degree can be tuned a bit for the coming year because of known and projected weather conditions (like expected snowfall). I am not aware of any such year-to-year conditional shaping of long-term future wind and solar profiles. Thus, they must be simulated as being about like average, all the time (as described above being PacifiCorp's practice), even though after the fact, they never are like average in most days or even for the whole year.[12] This will become more problematic as more renewable resources are added to the PacifiCorp and other WECC members' fleet(s).

[12] There is some net renewable diversity that is gained by relying on a mix of solar and wind, as PacifiCorp is moving towards, but a lot of that benefit is gained at the seasonal and diurnal time frames (spring night-time wind versus summer day-time solar) that can be forecast on average at the beginning of the year, e.g. in the TAM. There may be some additional diversity benefits within shorter time frames, but measuring those would depend on knowing the short-term correlations between solar and wind output (e.g., when the sun goes behind a cloud, does the wind tend to blow more or less?). I am not aware of any utility that has measured or is modeling this level of detail in their renewable resource planning or hedging practices.

- System models do not calculate feedback effects on fuel prices, other suppliers' behavior (such as scarcity bidding), or price-sensitive loads from unforeseen shifts in market conditions.
- Loads depend on circumstances well beyond what a utility considers, especially commercial and industrial loads that can vary with tariffs, competition from other countries, and the price of non-electric commodity inputs to their production.

All of this simply reflects that there is never going to be a forecasting tool for net loads, solar, or wind, or for projecting market balancing operations, that will not have *ex post* errors. Models are intrinsically smoother and nicer than real world conditions, and smoothness typically results in under-estimation. This exposure to errors will persist and will likely grow under the direction the industry is headed. And because the supply curve for the industry is increasingly upward sloping as net demand increases and flatter and more slowly declining when net demand decreases, whatever errors remain will tend to have a positive cost, not wash out. This appears to be a significant cause of the persistent NPC under-recoveries for PacifiCorp.

Q. What are the implication of these key drivers of NPC deviations and under-recovery for the appropriate mechanism to allocate NPC risks between PacifiCorp shareholders and ratepayers?

A. These key drivers of NPC under-recovery (deviations in load, hydro, wind, and market spot power prices) are outside PacifiCorp's control. They may be amenable in principle to better forecasting, though no such mechanism has been identified or approved, or ad hoc adjustments (like including a correction factor based on history as an uplift over forecasted NPC unit costs)—but the difficulties are intrinsic to the fact that this component of NPC arises on the margin in relation to both unforeseen conditions and how those affect the marginal positions of every other power market participant in the WECC that is able to trade with PacifiCorp.

Because these are so uncontrollable (and none of the past variances have been attributed to imprudent or inefficient practices by PacifiCorp) there is no improvement or benefit that can be expected or incentivized by not allowing 100 percent of NPC deviations to pass straight through to customers. Just as one would not be able to do a better job in his or her profession if their bonus was tied to how the weather turned out.

Q. If all of these problems are intrinsic to forecasting and resource planning in the industry, doesn't that just make them a part of normal business risk that the utilities should just incur and internalize, e.g., as part of what their allowed ROE covers?

A. No, they indeed are normal to experience, but it is not normal for them to be systematically under-recovered by virtue of asymmetric risk-sharing and broad exclusions for cost recovery. They reflect prudently incurred costs that are simply extremely difficult to forecast. Thus it is not productive, or equitable, or incentivizing to treat them as just a normal risk that should be absorbed by utility shareholders. In particular, it is not correct to construe them as a risk that is implicitly covered by the allowed ROE. The allowed ROE is predicated on (and will be sufficient to cover comparable financial risks for investors when it is) being added to an allowance for other non-financial costs that is itself unbiased. The intention is to allow a risk-adjusted, time-deferred recovery of prudently incurred costs, including return on and of capital. But that can only occur if indeed <u>all</u> of the prudent costs other than cost of capital are themselves fully in the revenue requirement. [13]

What my analysis demonstrates, and the persistent NPC shortfalls reveal, is that such operating-cost recovery completeness is not the case for PacifiCorp. There is a missing type of cost from the asymmetry of dealing with balancing transactions in a dynamic market. This is a prudent cost, arising because of massive savings that are possible when multiple companies pool and diversify their risks and opportunities in a market. In essence, they are a byproduct of this benefit. It is not reasonable to treat the residual forecasting bias that arises from taking advantage of the market as a cost that should be borne by utility shareholders.

In fact, because it is both normal and prudently incurred, most other states allow their utilities to pass through all of their NPC to their ratepayers without deadbands or earnings tests, as I explain further in Section VI.

Q. Is there any incentive benefit from putting these costs at risk, via the deadbands and profit collars on the current PCAM?

A. No. As noted above, these costs cannot be mitigated by alternative forecasting or hedging, and they are not the result of poor operational decisions. They are prudent, but fundamentally uncontrollable, and therefore should be fully recoverable. Making the utility bear them at risk when they cannot do anything material to reduce or improve them is simply punitive.

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[13] Even if one thought that this type of non-recovery risk was something that shareholders anticipate and build in a risk premium for it—which I reiterate is not the case—it is unlikely that the measured cost of capital for PacifiCorp would properly capture that premium. This is because, as shown below in my survey of risk sharing by other utilities, almost no states other than the ones where PacifiCorp operates impose such NPC cost-recovery risks on their utilities. Thus the proxy groups for measuring cost of equity almost certainly would not include this problem. By removing this risk-sharing, PacifiCorp would be put on more equal terms with other utilities against which its risk is measured.

In fact, too much risk exposure tends to induce counterproductive behavior to try to avoid the problem. One way (in principle – NOT a recommendation) for PacifiCorp to do that would be to reduce its use of the market for balancing (sticking to the more knowable state of its own generation fleet) and to reduce its reliance on renewable generation. Those are obviously bad ideas, but they illustrate the fact that the NPC sharing rules currently in place punish PacifiCorp for pursuing those benefits, where the NPC under-recovery is simply a byproduct of being in the market with those resources.

V. NEED FOR PACIFICORP'S PROPOSED MODIFICATIONS TO THE PCAM IN OREGON GIVEN FUTURE MARKET TRENDS

Q. You have shown how the PCAM under-recovery variances have arisen in the past. How is the exposure to this problem likely to change in the coming years as PacifiCorp and other WECC utilities adjust their resource mixes?

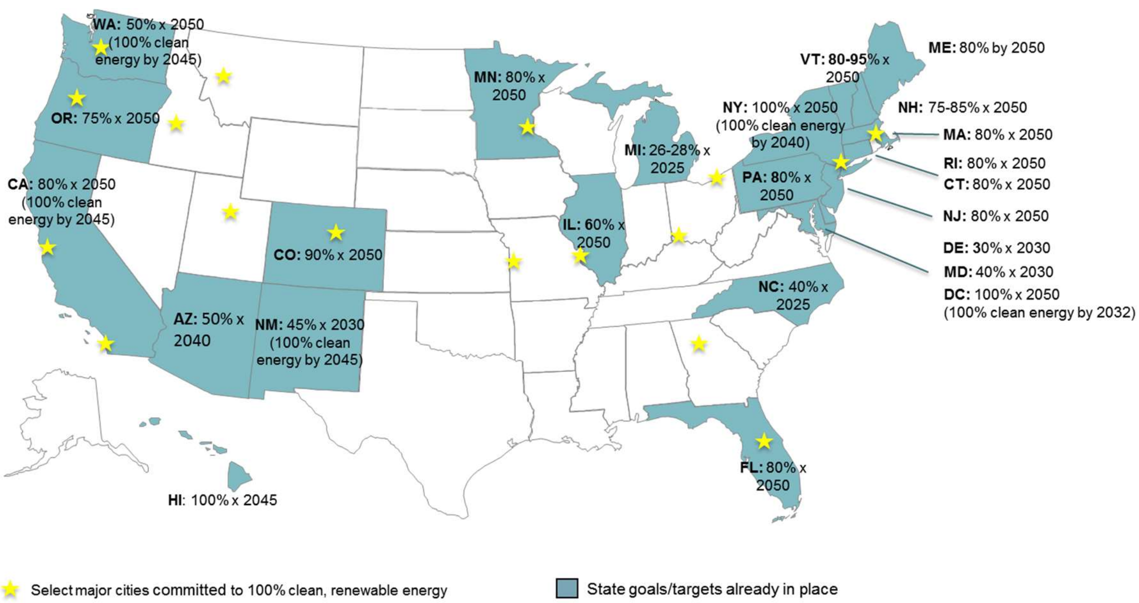
A. I expect under-recovery variances will become more problematic for PacifiCorp in the future, for several related reasons. First, as seen in Figure 8 many of the states or sometimes just the large cities in the WECC are pursuing public policy goals to try to dramatically decarbonize not just their electric sector but their entire economy, by backing out fossil fuel uses from transportation, heating, and some commercial applications. In particular, 10 states (plus Washington D.C. and Puerto Rico), including California, Washington, Nevada, and New Mexico, have made either 100 percent renewable energy or 100 percent clean energy commitments.[14] Other states have goals to at least significantly reduce fossil fuel use in their electricity

[14] *See 100 percent renewable targets*, ENERGYSAGE, https://news.energysage.com/states-with-100-renewable-targets/.

generation, including Oregon with a 75 percent greenhouse gas reduction target by 2050. On top of that, more than 150 cities have committed to transition to 100 percent renewable energy, including Portland, Boise, and Missoula.[15]

Regardless of such policies, the relative cost of renewables versus fossil generation has shifted, generally shifting towards greater economical roles for renewables under more and more conditions. This makes renewable resources attractive whether they are mandated or not. Several utilities have announced plans to back out existing fossil plants and replace them with a mix of renewables and storage (and sometimes gas peakers) over the next decade, including Public Service Company of New Mexico, Arizona Public Service (APS), Idaho Power, Xcel, among others.[16]

Figure 8: Deep Greenhouse Gas Reduction Targets for U.S. States and Cities



Notes:
[1] State goals and targets from https://www.c2es.org/content/state-climate-policy. Different states have different baseline years to measure future reduction goals.
[2] City data from https://www.sierraclub.org/ready-for-100/commitments.

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[15] *See Ready for 100*, SIERRA CLUB, https://www.sierraclub.org/ready-for-100/commitments.
[16] *See Utility Carbon Reduction Tracker*, SMART ELECTRIC POWER ALLIANCE, https://sepapower.org/utility-carbon-reduction-tracker/.

Q. How does PacifiCorp's planned generation resource mix reflect these policy and technology trends for the future?

A. According to the Company's 2019 IRP, PacifiCorp is expecting to substantially increase the share of renewables and energy storage in its resource mix.[17] For instance, the preferred portfolio includes over 6,300 MW of new solar resources and over 4,600 MW of new wind resources over the next 20 years, representing about 100 percent of PacifiCorp's current total fleet capacity. The 2019 IRP's least-cost portfolio also includes about 600 MW of battery storage by 2023 and an additional 2,200 MW by 2038. This is a significant development, given that PacifiCorp does not currently own any solar generation resources or significant battery storage facilities.[18]

Q. Please explain why this shift is likely to exacerbate NPC under-recovery risks.

A. There are two different impacts on NPC from greater use of renewables. The first is to lower the average cost of fuel by virtue of the "free energy" (i.e. zero short run marginal costs, ignoring fixed capital costs) for the new supplies. This will lower the base rates component forecast by the TAM. However, the second impact is more complex, arising because of the difficulty in forecasting the short-term renewable patterns and having to offset deviations from plan in those hours with re-dispatch or market transactions (i.e. the major drivers of the NPC deviations). More specifically:

[17] *See In the matter of PacifiCorp, dba Pacific Power, 2019 Integrated Resource Plan*, Docket No. LC 70, PacifiCorp's 2019 Integrated Resource Plan (Oct. 18, 2019).

[18] Note that battery storage can help with the imbalance problem, by servicing some of the short daily periods when there is less renewable output than expected. However, at the level of roughly 1 MW of storage per 16 MWs of renewables, this will not materially alter the NPC problems described herein. The large increase in renewables will overwhelm the storage offsets.

- In the hours when they do not produce as much as needed or expected, there may be higher than now-typical unit costs from paying fast-response resources or demand-response adjustments to load for absorbing the shortfalls, which can occur on short notice (and will be essentially impossible to forecast over the horizons of annual or longer rate-setting processes). So balancing energy costs may be higher and more volatile than in the past.
- There will tend to be more correlation across the entire power system fleet in output, as PacifiCorp and much of the WECC moves towards more renewables, because they are all responding to shared conditions from the sun or wind. It is of course true that there is geographic diversity across large regions (hundreds of miles or more) for when and where these renewable "fuels" will be active, but it is also true that huge areas (many states at a time) can experience similar weather of being overcast or not windy (or vice versa, very windy). Unlike fossil plants, whose outage characteristics are relatively independent, renewables will tend to face this risk jointly, thus causing much bigger (and perhaps more sudden) shifts over time in what I referred to as net load above.
- As the transportation and heating sectors are decarbonized, there will be more electric load on the system—by some estimates, perhaps doubling (or more) because the majority of greenhouse gases in the economy now stem much more from those sectors than from electricity generation. The apparently most economical way to reduce them is to convert those loads to electricity and

then supply those new needs with lower-emission power.[19] This shift will make weather sensitivity greater for the electric loads served by PacifiCorp and others.

Q. Can you provide some empirical support for these qualitative descriptions of the shift towards renewables?

A. Yes. According to the U.S. Energy Information's Administration (EIA) Annual Energy Outlook 2020, generation from renewables nationally will increase from 18 percent to 38 percent of total generation by 2050, with solar contributing to almost half of that share.[20] In the "West" region, which includes Oregon, Idaho, and Wyoming, EIA projects generation from renewables will double by 2050. Consistent with general market outlook, EIA anticipates that the wave of coal plant retirements will continue. In the last decade, coal plant owners retired (or planned to retire) more than 546 coal plant units, totaling about 102 gigawatts (GW) of generating capacity, or about 1/3 of the total coal fleet relative to 2008.[21] An additional 17 GW of coal capacity is planned to be retired by 2025.

Furthermore, states will need to accelerate their renewable deployment efforts in order to meet the greenhouse gas reduction and/or clean energy targets that I mention above.

[19] It is also possible that biofuels will become available so that those loads do not have to be electrified, but the process of making the clean biofuels may itself involve more electricity production than the end use energy they will serve. So either way, electric demands grow dramatically.

[20] U.S. ENERGY INFORMATION ADMINISTRATION, ANNUAL ENERGY OUTLOOK 2020 – ELECTRICITY, *available at* https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Electricity.pdf.

[21] U.S. ENERGY INFORMATION ADMINISTRATION, TODAY IN ENERGY (July 26, 2019), *available at* https://www.eia.gov/todayinenergy/detail.php?id=40212.

Q. Please summarize the consequences of this trend for NPC.

A. The main effects are to enlarge the difficulties already experienced. Renewable generation will be more significant but is difficult to forecast, especially far in advance for rate setting. Renewables can also be quite variable over the short run, and will tend to do so en masse rather than independently, creating shared conditions of overall shortfall or excess supply when they vary from expectations, likely pushing replacement market prices far off of their prior expectations as well. And there will be more load exposed to this situation, so the total costs at risk will be larger (offset in part by the expected part of the energy price, when the renewables perform as hoped, lower in cost). Overall, it should be beneficial, but it will make NPC variance due to uncertainty in net load much greater. And as shown above, those variances tend to cause losses on either side, whether positive or negative, because of their correlation with market prices and the asymmetry of prices for unplanned higher demand going up faster than they fall for unplanned softening of demand.

It is also likely that all the utilities in WECC will move to greater and greater reliance on market-mediated coordination as more renewables are used, largely to take advantage of geographic diversity and to share access to non-renewable balancing resources that may be used only occasionally (less often but more acutely) than such plants are now used. This means more of the balancing costs in NPC will depend on actions of other utilities that are not part of the control or forecasts of PacifiCorp.

VI. REVIEW OF PCAM IMPLEMENTATION IN OTHER STATES

Q. Have you reviewed the PCAM implementation in other states?

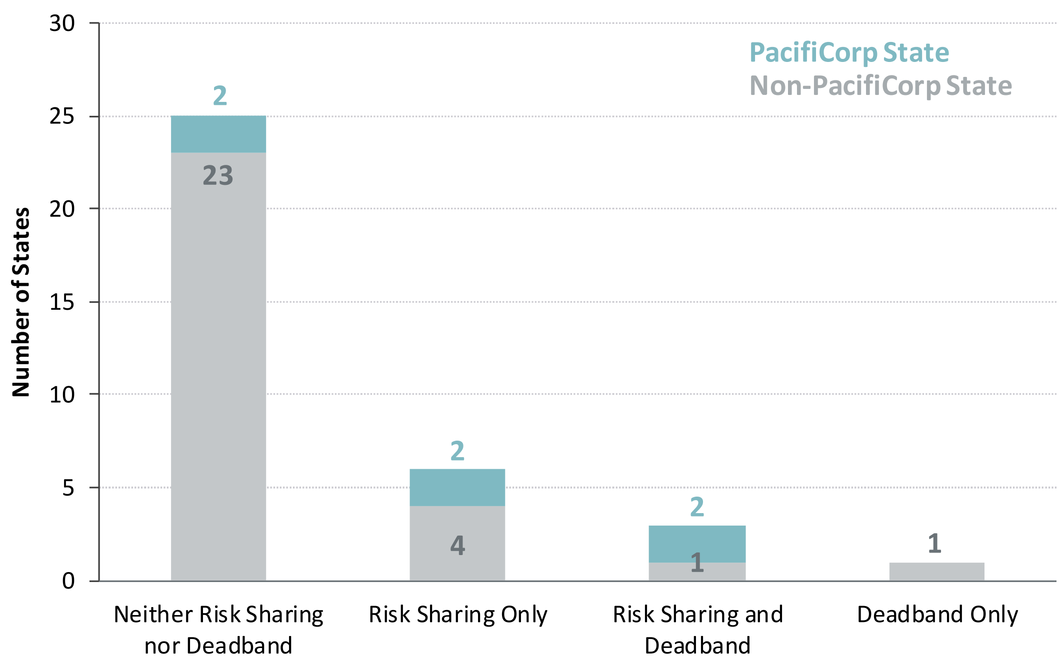
A. Yes. I have compiled state by state profiles of current policies towards PCAM-like cost recovery mechanism for vertically integrated utilities, excluding those that have unbundled generation from delivery services and/or that participate in an independent system operator (ISO) and within have deregulated merchant generation. For instance, this means that Texas utilities in the Electric Reliability Council of Texas are irrelevant, as are the vertically unbundled utilities in PJM, New York, etc.—but the vertically bundled utilities in Midcontinent Independent System Operator (MISO) are relevant. In total, I reviewed the fuel adjustment clauses in force in 2019 across 35 states that have regulated electricity power supply. The results of my survey detailing the structure of each state's enacted adjustment clauses is attached as Exhibit PAC/602.

Q. Based on your review, is the Company's existing PCAM consistent with those of most electric utilities around the country?

A. No. The Company's existing PCAM, which includes risk sharing of 90 percent to customers and 10 percent to stakeholders outside a deadband range of -$15 million to $30 million, and then profit collars on whether the magnitude is material, is inconsistent with prevalent industry practice in two regards. First, of the 35 relevant states, the vast majority do not apply any risk-sharing mechanisms or deadbands, instead passing through all NPC-type costs 100 percent to customers (often subject to an occasional prudence review). A handful apply one or both of risk-sharing or deadbands, but often those are states in which PacifiCorp operates. Thus, PacifiCorp's exposure to this policy is almost unique. Second, the few risk-sharing mechanisms that are applied elsewhere are usually milder and more symmetrical than those facing PacifiCorp.

These findings are summarized in Figure 9 below. For each bar, the teal shading indicates the number of states in which PacifiCorp operates, while the gray shading represents the remaining states in which PacifiCorp does not operate. For example, PacifiCorp states make up two out of the six states with a risk-sharing mechanism only, and two out of three of the states with both a risk-sharing and deadband mechanism. In other words, nearly half of all states with risk sharing are states that lie within PacifiCorp's service territory.

Figure 9: Structure of Fuel Adjustment Clauses in Benchmarked States



Source and Notes:

The Brattle Group interpretation of deadband and risk-sharing mechanisms, based on descriptions of fuel adjustment clauses in SNL Energy Regulatory Research Associates (RRA) summaries and utility filings. PacifiCorp states consist of those in the service territories of Pacific Power (California, Washington, Oregon) or Rocky Mountain Power (Idaho, Utah, and Wyoming).

Digging under the surface of these results, of the three states that have both risk-sharing and deadbands, two are Oregon and Washington where PacifiCorp operates. Of the six other states with just a risk-sharing mechanism, five (Hawaii, Idaho, Missouri, Montana, and Wyoming) generally allow their utilities to recover between 90 percent and 98 percent of cost variations, with the exception of a 70 percent sharing clause for PacifiCorp's PCAM in Wyoming.[22] Thus these other utilities' recovery shares are either consistent with or higher than the one under PacifiCorp's current PCAM in Oregon. Perhaps more importantly, those shared amounts are not subject to asymmetric deadbands or wide profit collars that further skew or restrict cost recovery. Thus they are more amenable to neutral (zero) expected impacts on costs, to the extent that forecasting errors tend to balance out over time.

Q. Is there any important distinction in these patterns when focusing on just vertically integrated utilities in regional-transmission organizations (RTOs) and ISO regions?

A. No. Of the 35 regulated states, 20 operate in RTO/ISO regions.[23] I analyzed the adjustment clauses for their utilities (that participate in these RTO/ISO markets while owning their own generation) and found they almost all have full and unfettered flow-

[22] In Wyoming, Cheyenne Light Fuel & Power can only allocate 85 percent of steam production cost variations to ratepayers, but 95 percent of all other eligible costs, with the latter making up a vast majority of its power costs. The fifth state with a risk sharing mechanism, but no deadband, Arizona, has eliminated the 90/10 cost-sharing mechanism that was in place in 2012, but maintains a $0.004/kWh annual cap on increases or decreases to the adjustment clause. If a true-up stays in keeping with this cap, APS can recover its full fuel and purchased power costs.

[23] The 20 states I reviewed (Arkansas, California, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Mexico, North Carolina, North Dakota, Oklahoma, South Dakota, Vermont, Virginia, West Virginia, and Wisconsin) participate in California Independent System Operator, Independent System Operator of New England, MISO, PJM, and Southwest Power Pool.

through of NPC-type costs. Only two (Vermont and Wisconsin) have fuel and purchased power adjustment clauses with deadbands. But in both cases, these deadbands are narrower than the current one in place for PacifiCorp's PCAM in Oregon, and they are completely symmetric, while the deadbands for Oregon are skewed to impose a larger share of losses for utilities than they allow retention of gains.[24] Similarly, only three states (Vermont, Missouri, Montana) incorporate a risk-sharing mechanism for recovery of fuel and purchased power costs.

VII. CONCLUSIONS

Q. Please summarize your conclusions.

A. Due to Oregon's wide and asymmetric deadbands and profit collars on NPC risk-sharing, PacifiCorp has experienced systematic NPC under-recovery in the past several years, which has accumulated to approximately $77 million of losses since 2014. These shortfalls are not arising because of occasional bad luck in the market, or bad forecasting, or improper or inefficient operations, but because of a flawed design for the PCAM mechanism itself.

As constructed, the PCAM does not accommodate the fact that due to more reliance on renewables and market participation (both beneficial on average), there is more irreducible forecast error in the projected NPCs. Worse, the error is not just noise but a downward bias, whereby the costs of balancing the system are intrinsically missed and omitted from the requested total costs. As a result, realized NPC tend to be higher than were forecast in rates, and there is persistent under-

[24] Wisconsin has a deadband of +/- 2 percent, and Vermont has a deadband of +/- $0.3 million per year. In contrast, the current deadband for PacifiCorp in Oregon is -$15 million over-recovery and +$30 million under-recovery, representing about 4-8 percent of the actual NPC in Oregon. That is, the Company needs a very large (8 percent) under-recovery of its Oregon NPC before it can even qualify for partial sharing.

recovery. Balancing transactions are not forecast precisely because they arise from realized conditions not being like the forecast. Perhaps surprisingly, when they occur, they tend to involve losses whether purchases or sales. This is because if more supply is needed than was expected, it will tend to have to be purchased in a tight market in which others are often experiencing similar shortages (or it must be supplied from the highest part of the dispatch supply curve that was not planned to be used). On the other side, when realized demand is below forecast, sales of unneeded power or fuel will tend to be dumped into a soft market with less than full recovery of whatever covering transactions or expenses were normally expected to have been needed.

These difficulties are normal for utility planning, but it is not normal for a utility to have to absorb most of such variances from forecast costs. It would be one thing to put the variances at risk or disallow the variances if the unrecovered costs stemmed from factors that PacifiCorp could control. Here, that is not the case, so there is no efficiency or incentive benefit to imposing risk-sharing on NPC. As I have demonstrated, the large volume of purchases and sales for system balancing in the wholesale markets are the main drivers. It is intuitive that these transactions occur due to many factors that are beyond PacifiCorp's control or prediction, because the Company would have to not only accurately forecast the conditions of its system (e.g. all the short-term weather) throughout the test year but also to correctly anticipate the needs, surprises, and (re)actions of other market participants throughout the market region(s). This is clearly impossible. Indeed, best-practices market modeling tools do not even support simulating most of those elements.

PacifiCorp's increasing use of renewables and broader participation in regional power markets is a good thing, surely reducing NPC on average. But doing so comes with a side-effect of more exposure to short-term, uncontrollable, difficult to forecast, and only partially hedge-able transactions that tend to have a persistent net cost. This net cost is inadvertently excluded from the base rates. All utilities face this problem, and since it is uncontrollable and not able to be fixed with better forecasting, the vast majority of their state regulators allow full cost recovery of NPC with no risk sharing. Only a handful impose any risk-sharing or deadband conditions, and those are 1) mostly the PacifiCorp states and 2) they mostly have milder and more symmetric risk sharing than Oregon. Thus, it is not normal business risk in the industry to face losses from these prudent costs.

A better solution, which would put PacifiCorp in risk-exposure parity with other investor-owned utilities, would be to go to full cost flow-through of NPC to customers, subject to a prudence review of actual operations. This would be a more relevant form of oversight than the current arrangement, which tends to confound intrinsic forecasting difficulties with business operations. Making this improvement in regulatory practice likely to become even more important in the future, due to the strong shift towards more renewable generation in the PacifiCorp fleet (and throughout much of the WECC).

Q. Does this conclude your direct testimony?

A. Yes it does.

Docket No. UE 374
Exhibit PAC/601
Witness: Frank Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Frank Graves

Resume

February 2020

FRANK C. GRAVES

Principal

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Mr. Frank C. Graves is a Principal of The Brattle Group who specializes in regulatory and financial economics, especially for electric and gas utilities, and in litigation matters related to securities litigation, damages from breached energy contracts, and risk management.

He has over 35 years of experience assisting utilities in forecasting, valuation, and risk analysis of many kinds of long range planning and service design decisions, such as generation and network capacity expansion, fuel and gas supply procurement and hedging, pricing and cost recovery mechanisms, cost and performance benchmarking, renewable asset selection and contracting, and new business models for distributed energy technologies. He has testified before many state regulatory commissions and the FERC as well as in state and federal courts and arbitration proceedings on such matters as integrated resource planning (IRPs), energy contract disputes, the prudence of investment and contracting decisions, risk management, costs and benefits of new services, policy options for industry restructuring, adequacy of market competition, and competitive implications of proposed mergers and acquisitions.

In the area of financial economics, he has assisted and testified in civil cases in regard to contract damages estimation, securities litigation suits, special purpose audits, tax disputes, risk management, and cost of capital estimation, and he has testified in criminal cases regarding corporate executives' culpability for securities fraud.

He received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

AREAS OF EXPERTISE

- Utility Planning and Operations
- Regulated Industry Policy and Restructuring
- Energy Market Competition
- Electric and Gas Transmission
- Financial Analysis and Commercial Litigation

PROFESSIONAL AFFILIATIONS

- IEEE Power Engineering Society
- Mathematical Association of America
- American Finance Association

Recent Activities

Client Engagements

- Uncertainty over the pace and extent of potential distributed energy resources (DERs) adoption by customers makes load forecasting and system planning much more complex, possibly involving future "tipping points" when DER use could accelerate rapidly. However, statistical histories on these improving technologies are not yet very informative as to when or why such a shift might occur. Mr. Graves has assisted several distribution utilities with a new, behavior-based modeling technique for long range system planning that simulates possible paths to DER adoption, utilizing system dynamics methods that recognize the feedbacks between offered electricity prices, customers' propensities to use DERs, declining technology costs, cost shifting to non-users, and other interdependencies.
- With improvements in performance and cost of microgeneration, many hospitals, universities, and similar campuses are considering combined heat and power supply as an alternative to utility energy services. Mr. Graves has helped several such entities evaluate potential benefits of CHP, including choosing the preferred size and mix of technology and risk analysis of terms in financial and operating contracts for the CHP systems.
- Several states and cities have set goals of deep decarbonization of their local economies, often dubbed "80 by 50" if they aspire to 80% reductions in GHG emissions by 2050. Achieving this will involve radical change in the economy of those regions, potentially with dramatic load growth due to electrification and massive investment in new infrastructure for end-use and power supply and delivery. Mr. Graves has built models that show what types and degree of change could arise, and what they might cost depending on how such transformations are incentivized or enforced.
- Wildfires in California have become catastrophic in the past few years, creating both financial turmoil for the utilities and controversy over how to insure and manage this problem. Mr. Graves has been extensively involved in estimating the expected, growing cost of this problem and the design of mechanisms to insure it and compensate investors for the likelihood of uncompensated costs from fire damages.

Testimony

On behalf of Public Service Company of New Mexico, presented testimony before the New Mexico Public Regulation Commission on the merits of replacing the San Juan Generating Station coal units with a fleet of renewables, storage and gas-fired peakers, and on the reasons for appropriateness of allowing full recovery of sunk costs despite early retirement. Case No. 19-00018-UT, November 15, 2019.

On behalf of both Southern California Edison and Pacific Gas & Electric Company, presented direct and rebuttal testimony co-authored with Robert Mudge in regard to cost of wildfire risk under AB 1054, a state policy to create a fire insurance mechanism. Applications 19-04-014 and 19-04-015, September 4, 2019.

For Nicor Gas, a natural gas distribution company, Mr. Graves co-authored testimony on the cost of equity capital utilizing a broad spectrum of risk-pricing methods and explaining how financial leverage affects it. Testimony was filed with the Illinois Commerce Commission, Docket 18-xxxx, November 9, 2018.

For the electric transmission division of Pacific Gas & Electric, Mr. Graves presented testimony and co-authored an accompanying report on the cost of capital impacts from the extreme risks arising from potential liability for damages caused by large wildfires in California. Testimony before the FERC, Docket ER19- ___ - 000, Exhibit PGE-0019, October 1, 2018.

For the Government of Colombia, written and oral testimony in regard to apparent misrepresentations of coal mine development costs and expected profitability by Glencore Corporation that adversely affected royalty payments for Colombia. Heard in the International Court of Arbitration, ICSID Case No ARB/16/6, Washington DC, June 2018.

Publications

"System Dynamics Modeling: An Approach to Planning and Developing Strategy in the Changing Electricity Industry" (with Toshiki Bruce Tsuchida, Philip Q Hanser, and Nicole Irwin), Brattle White Paper, April 2019.

"California Megafires: Approaches for Risk Compensation and Financial Resiliency Against Extreme Events" (with Robert S. Mudge and Mariko Geronimo Aydin), Brattle White Paper, October 1, 2018.

"Retail Choice: Ripe for Reform?" (with Agustin Ros, Sanem Sergici, Rebecca Carroll and Kathryn Haderlein), Brattle White Paper, July 2018.

"Resetting FERC RoE Policy; a Window of Opportunity" (with Robert Mudge and Akarsh Sheilendranath), Brattle White Paper, May 2018

Full C.V.

REPRESENTATIVE ENGAGEMENTS

Utility Planning and Operations

- Uncertainty over the pace and extent of potential distributed energy resources (DERs) adoption by customers makes load forecasting and system planning much more complex, possibly involving future "tipping points" when DER use could accelerate rapidly. However, statistical histories on these improving technologies are not yet very informative as to when or why such a shift might occur. Mr. Graves has assisted several distribution utilities with a new, behavior-based modeling technique for long range system planning that simulates possible paths to DER adoption, utilizing system dynamics methods that recognize the feedbacks between offered electricity prices, customers' propensities to use DERs, declining technology costs, cost shifting to non-users, and other interdependencies.
- Many large high-tech firms are selling power supply services relying entirely on renewable resources. This can only be done for average or cumulative power needs, but the resulting green energy production will not match the time pattern of those firms' demand. Mr. Graves lead a team evaluating how much risk is borne by a utility from offering such service over many years, when it will have to balance a significant green supply (such as rooftop and utility-scale solar) against its own load and the regional market.
- With improvements in performance and cost of microgeneration, many hospitals, universities, and similar campuses are considering combined heat and power supply as an alternative to utility energy services. Mr. Graves has helped several such entities evaluate potential benefits of CHP, including choosing the preferred size and mix of technology and risk analysis of terms in financial and operating contracts for the CHP systems.
- Many utilities are facing a concern through the expected useful lives of their coal plants are being shortened by low gas prices and increased use of renewables. Mr. Graves helped a utility justify early retirement of a coal plant with full recovery of its stranded costs, when that plan could be replaced more economically with new wind plants while the tax incentives for their development were still in effect.
- Mr. Graves developed a valuation and risk analysis model showing that a utility's RFP for new generation could be better served by deferring new plant construction for a few years via a less costly and less risky transitional market-based power supply contract with price and quantity terms shaped to match the shifting needs over time until supply shortfalls were large enough to justify the investment in a new power plant at efficient scale. The parties negotiated a multi-year contract along these lines in lieu of pursuing the construction alternative that initially came out of the RFP selection.

- In Maryland the electric distribution companies administer SOS (Standard Offer Service) supply procurement and accounting to backup customers who do not use a competitive retail power supplier. The utilities are authorized to recover both the direct and financing costs of that service plus a return on equity. Mr. Graves developed a method for sizing an appropriate equity return for the SOS risks and administrative services based on analogies to various intermediation businesses on the internet, such as EBay, PayPal, and others—in which, like SOS intermediation, the businesses do not take ownership for the products conveyed. Testimony was provided.
- Mr. Graves co-lead a team of Brattle analysts to assess the relative influence of different factors that were affected by the "Polar Vortex" cold snap of early 2014 that caused dramatic spikes in local power and gas prices in parts of the mid-Atlantic and northeastern US. The risks of similar recurring events were assessed in light of pending expansions of the electric and gas transmission grids, as well as likely coal plant retirements.
- For the Board of Directors or executive management teams of several utilities, Mr. Graves has lead strategic retreats on disruptive issues facing the electric industry in the future and how a utility should choose which risks and opportunities to embrace vs. avoid.
- Air quality and other power plant environmental regulations are being tightened considerably in the period from about 2014-2018. Mr. Graves has co-developed a market and financial model for determining what power plants are most likely to retire vs. retrofit with new environmental controls, and how much this may alter their profitability. This has been used to help several power market participants assess future capacity needs, as well as to adjust their price forecasts for the coming decade.
- Successful merchant power plant development and financing depends in part on obtaining a long term power purchase agreement. Mr. Graves directed a study of what pricing points and risk-sharing terms should be attractive to potential buyers of long-term power supply contracts from a large baseload facility.
- Many utilities are pursuing smart meters and time-of-use pricing to increase customer ability to consume electricity economically. Mr. Graves has led a study of the costs and benefits of different scales and timing of installation of such meters, to determine the appropriate pace. He has also evaluated how various customer incentives to increase conservation and demand response might be provided over the internet, and how much they might increase the participation rates in smart meter programs.
- Wind resources are a critical part of the generation expansion plans and contracting interests of many utilities, in order to satisfy renewable portfolio standards and to reduce long run exposure to carbon prices and fuel cost uncertainty. Mr. Graves has applied Brattle's risk modeling capabilities to simulate the impacts of on- and off-shore wind resources on the potential range of costs for portfolios of wholesale power contracts designed to serve retail electricity loads. These impacts were compared to gas CCs and CTs and to simply buying more from the wholesale market to identify the most economical supply strategy.

- For a municipal utility with an opportunity to invest in a nuclear power plant expansion, Mr. Graves lead an analysis of how the proposed plant fit the needs of the company, what market and regulatory (environmental) conditions would be required for the plant to be more economical than conventional fossil-fired generation, and how the development risks could be shared among co-owners to better match their needs and risk tolerances. He also assessed the market for potential off-take contracts to recover some of the costs and capacity that would be available for a few years, ahead of the needs of the municipal utility.
- The potential introduction of environmental restrictions or fees for CO2 emissions has made generation expansion decisions much more complex and risky. He helped one utility assess these risks in regard to a planned baseload coal plant, finding that the value of flexibility in other technologies was high enough to prefer not building a conventional coal plant.
- Mr. Graves helped design, implement, and gain regulatory approvals for a natural gas procurement hedging program for a western U.S. gas and electric utility. A model of how gas forward prices evolve over time was estimated and combined with a statistical model of the term structure of gas volatility to simulate the uncertainty in the annual cost of gas at various times during its procurement, and the resulting impact on the range of potential customer costs.
- Generation planning for utilities has become very complex and risky due to high natural gas prices and potential CO2 restrictions of emission allowances. Some of the scenarios that must be considered would radically alter system operations relative to current patterns of use. Mr. Graves has assisted utilities with long range planning for how to measure and cope with these risks, including how to build and value contingency plans in their resource selection criteria, and what kinds of regulatory communications to pursue to manage expectations in this difficult environment.
- For a Midwestern utility proposing to divest a nuclear plant, Mr. Graves analyzed the reasonableness of the proposed power buyback agreement and the effects on risks to utility customers from continued ownership vs. divestiture. The decommissioning funds were also assessed as to whether their transfer altered the appropriate purchase price.
- Several utilities with coal-fired power plants have faced allegations from the U.S. EPA that they have conducted past maintenance on these plants which should be deemed "major modifications", thereby triggering New Source Review standards for air quality controls. Mr. Graves has helped one such utility assess limitations on the way in which GADS data can be used retrospectively to quantify comparisons between past actual and projected future emissions. For another utility, Mr. Graves developed retrospective estimates of changes in emissions before and after repairs using production costing simulations. In a third, he reviewed contemporaneous corporate planning documents to show that no increase in emissions would have been expected from the repairs, due to projected reductions in future use of the plant as well as higher efficiency. In all three cases, testimony was presented.

- The U.S. Government is contractually obligated to dispose of spent nuclear fuel at commercial reactors after January 1998, but it has not fulfilled this duty. As a result, nuclear facilities that are shutdown or facing full spent fuel pools are facing burdensome costs and risks. Mr. Graves prepared developed an economic model of the performance that could have reasonably been expected of the government, had it not breached its contract to remove the spent fuel.
- Capturing the full value of hydroelectric generation assets in a competitive power market is heavily dependent on operating practices that astutely shift between real power and ancillary services markets, while still observing a host of non-electric hydrological constraints. Mr. Graves led studies for several major hydro generation owners in regard to forecasting of market conditions and corresponding hydro schedule optimization. He has also designed transfer pricing procedures that create an internal market for diverting hydro assets from real power to system support services firms that do not yet have explicit, observable market prices.
- Mr. Graves led a gas distribution company in the development of an incentive ratemaking system to replace all aspects of its traditional cost of service regulation. The base rates (for non-fuel operating and capital costs) were indexed on a price-cap basis (RPI-X), while the gas and upstream transportation costs allowances were tied to optimal average annual usage of a reference portfolio of supply and transportation contracts. The gas program also included numerous adjustments to the gas company's rate design, such as designing new standby rates so that customer choice will not be distorted by pricing inefficiencies.
- An electric utility with several out-of-market independent power contracts wanted to determine the value of making those plants dispatchable and to devise a negotiating strategy for restructuring the IPP agreements. Mr. Graves developed a range of forecasts for the delivered price of natural gas to this area of the country. Alternative ways of sharing the potential dispatch savings were proposed as incentives for the IPPs to renegotiate their utility contracts.
- For an electric utility considering the conversion of some large oil-fired units to natural gas, Mr. Graves conducted a study of the advantages of alternative means of obtaining gas supplies and gas transportation services. A combination of monthly and daily spot gas supplies, interruptible pipeline transportation over several routes, gas storage services, and "swing" (contingent) supply contracts with gas marketers was shown to be attractive. Testimony was presented on why the additional services of a local distribution company would be unneeded and uneconomic.
- A power engineering firm entered into a contract to provide operations and maintenance services for a cogenerator, with incentives fees tied to the unit's availability and operating cost. When the fees increased due to changes in the electric utility tariff to which they were tied, a dispute arose. Mr. Graves provided analysis and testimony on the avoided costs associated with improved cogeneration performance under a variety of economic scenarios and under several alternative utility tariffs.

- Mr. Graves has helped several pipelines design incentive pricing mechanisms for recovering their expected costs and reducing their regulatory burdens. Among these have been Automatic Rate Adjustment Mechanisms (ARAMs) for indexation of operations and maintenance expenses, construction-cost variance-sharing for routine capital expenditures that included a procedure for eliciting unbiased estimates of future costs, and market-based prices capped at replacement costs when near-term future expansion was an uncertain but probable need.
- For a major industrial gas user, he prepared a critique of the transportation balancing charges proposed by the local gas distribution company. Those charges were shown to be arbitrarily sensitive to the measurement period as well as to inconsistent attribution of storage versus replacement supply costs to imbalance volumes. Alternative balancing valuation and accounting methods were shown to be cheaper, more efficient, and simpler to administer. This analysis helped the parties reach a settlement based on a cash-in/cash-out design.
- The Clean Air Act Amendments authorized electric utilities to trade emission allowances (EAs) as part of their approach to complying with SO2 emissions reductions targets. For the Electric Power Research Institute (EPRI), Mr. Graves developed multi-stage planning models to illustrate how the considerable uncertainty surrounding future EA prices justifies waiting to invest in irreversible control technologies, such as scrubbers or SCRs, until the present value cost of such investments is significantly below that projected from relying on EAs.
- For an electric utility with a troubled nuclear plant, Mr. Graves presented testimony on the economic benefits likely to ensue from a major reorganization. The plant was to be spun off to a jointly-owned subsidiary that would sell available energy back to the original owner under a contract indexed to industry unit cost experience. This proposal afforded a considerable reduction of risk to ratepayers in exchange for a reasonable, but highly uncertain prospect of profits for new investors. Testimony compared the incentive benefits and potential conflicts under this arrangement to the outcomes foreseeable from more conventional incentive ratemaking arrangements.
- Mr. Graves helped design Gas Inventory Charge (GIC) tariffs for interstate pipelines seeking to reduce their risks of not recovering the full costs of multi-year gas supply contracts. The costs of holding supplies in anticipation of future, uncertain demand were evaluated with models of the pipeline's supply portfolio that reveal how many non-production costs (demand charges, take-or-pay penalties, reservation fees, or remarketing costs for released gas) would accrue under a range of demand scenarios. The expected present value of these costs provided a basis for the GIC tariff.
- Mr. Graves performed a review and critique of a state energy commission's assessment of regional natural gas and electric power markets in order to determine what kinds of pipeline expansion into the area was economic. A proposed facility under review for regulatory approval was found to depend strongly on uneconomic bypass of existing

pipelines and LDCs. In testimony, modular expansion of existing pipelines was shown to have significantly lower costs and risks.

- For several electric utilities with generation capacity in excess of target reserve margins, Mr. Graves designed and supervised market analyses to identify resale opportunities by comparing the marginal operating costs of all this company’s power plants not needed to meet target reserves to the marginal costs for almost 100 neighboring utilities. These cost curves were then overlaid on the corresponding curve for the client utility to identify which neighbors were competitors and which were potential customers. The strength of their relative threat or attractiveness could be quantified by the present value of the product of the amount, duration, and differential cost of capacity that was displaceable by the client utility.
- Mr. Graves specified algorithms for the enhancement of the EPRI EGEAS generation expansion optimization model, to capture the first-order effects of financial and regulatory constraints on the preferred generation mix.
- For a major electric power wholesaler, Mr. Graves developed a framework for estimating how pricing policies affect the relative attractiveness of capacity expansion alternatives. Traditional cost-recovery pricing rules can significantly distort the choice between two otherwise equivalent capacity plans, if one includes a severe “front end load” while the other does not. Price-demand feedback loops in simulation models and quantification of consumer satisfaction measures were used to appraise the problem. This “value of service” framework was generalized for the Electric Power Research Institute.
- For a large gas and electric utility, Mr. Graves participated in coordinating and evaluating the design of a strategic and operational planning system. This included computer models of all aspects of utility operations, from demand forecasting through generation planning to financing and rate design. Efforts were split between technical contributions to model design and attention to organizational priorities and behavioral norms with which the system had to be compatible.
- For an oil and gas exploration and production firm, Mr. Graves developed a framework for identifying what industry groups were most likely to be interested in natural gas supply contracts featuring atypical risk-sharing provisions. These provisions, such as price indexing or performance requirements contingent on market conditions, are a form of product differentiation for the producer, allowing it to obtain a price premium for the insurance-like services.
- For a natural gas distribution company, Mr. Graves established procedures for redefining customer classes and for repricing gas services according to customers' similarities in load shape, access to alternative gas supplies, expected growth, and need for reliability. In this manner, natural gas service was effectively differentiated into several products, each with price and risk appropriate to a specific market. Planning tools were developed for balancing gas portfolios to customer group demands.

- For a Midwestern electric utility, Mr. Graves extended a regulatory pro forma financial model to capture the contractual and tax implications of canceling and writing off a nuclear power plant in mid-construction. This possibility was then appraised relative to completion or substitution alternatives from the viewpoints of shareholders (market value of common equity) and ratepayers (present value of revenue requirements).
- For a corporate venture capital group, Mr. Graves conducted a market-risk assessment of investing in a gas exploration and production company with contracts to an interstate pipeline. The pipeline's market growth, competitive strength, alternative suppliers, and regulatory exposure were appraised to determine whether its future would support the purchase volumes needed to make the venture attractive.
- For a natural gas production and distribution company, he developed a strategic plan to integrate the company's functional policies and to reposition its operations for the next five years. Decision analysis concepts were combined with marginal cost estimation and financial pro forma simulation to identify attractive and resilient alternatives. Recommendations included target markets, supply sources, capital budget constraints, rate design, and a planning system. A two-day planning conference was conducted with the client's executives to refine and internalize the strategy.
- For the New Mexico Public Service Commission, he analyzed the merits of a corporate reorganization of the major New Mexico gas production and distribution company. State ownership of the company as a large public utility was considered but rejected on concerns over efficiency and the burdening of performance risks onto state and local taxpayers.

Regulated Industry Policy and Restructuring

- Several states and cities have set goals of deep decarbonization of their local economies, often dubbed “80 by 50” if they aspire to 80% reductions in GHG emissions by 2050. Achieving this will involve radical change in the economy of those regions, potentially with dramatic load growth due to electrification and massive investment in new infrastructure for end-use and power supply and delivery. Mr. Graves has built models that show what types and degree of change could arise, and what they might cost depending on how such transformations are incentivized or enforced.
- As wholesale power and natural gas prices have fallen, interest in “retail choice” for energy supply has increased. At the same time, some state regulatory agencies have become concerned that misleading marketing and non-competitive pricing are too common in the mass market, especially afflicting low income and senior residential customers. Mr. Graves lead a review of such concerns that compared practices and market performance in several states to identify what could be done to improve such services.
- For a group of utilities responding to a state mandate to consider means of encouraging distributed technologies to be assessed and incentivized in parity with central station generation, Mr. Graves and others at Brattle prepared alternative means of incorporating

marginal cost and externality value considerations into new cost/benefit assessment tools, procurement mechanisms, and supply contracting.

- For a mid-Atlantic gas distribution utility, Mr. Graves assessed mark to market losses that had occurred from gas supply hedges entered before spot prices declined precipitously. Concerns were voice that this outcome indicated the company's hedging practices were no longer attune to market conditions, so Mr. Graves developed and lead workshop between the company, intervener groups, and state commission staff to define new appropriate goals, mechanisms and review standards for revised risk management approach.
- For a major participant in the Japanese power industry contemplating reorganization of that country's electric sector following Fukushima, Mr. Graves lead a research project on the performance of alternative market designs around the US and around the world for vertical unbundling, RTO design, and retail choice.
- For several utilities facing the end of transitional "provider of last resort" (or POLR) prices, Mr. Graves developed forecasts and risk analyses of alternative procurement mechanisms for follow-on POLR contracts. He compared portfolio risk management approaches to full requirements outsourcing under various terms and conditions.
- For a large municipal electric and gas company considering whether to opt-in to state retail access programs, Mr. Graves lead an analysis of what changes in the level and volatility of customer rates would likely occur, what transition mechanisms would be required, and what impacts this would have on city revenues earned as a portion of local electric and gas service charges.
- Many utilities experienced significant "rate shock" when they ended "rate freeze" transition periods that had been implemented with earlier retail restructuring. The adverse customer and political reactions have led to proposals to annual procurement auctions and to return to utility-owned or managed supply portfolios. Mr. Graves has assisted utilities and wholesale gencos with analyses of whether alternative supply procurement arrangements could be beneficial.
- The impacts of transmission open access and wholesale competition on electric generators risks and financial health are well documented. In addition, there are substantial impacts on fuel suppliers, due to revised dispatch, repowerings and retirements, changes in expansion mix, altered load shapes and load growth under more competitive pricing. For EPRI, Mr. Graves co-authored a study that projected changes in fuel use within and between ten large power market regions spanning the country under different scenarios for the pace and success of restructuring.
- As a result of vertical unbundling, many utilities must procure a substantial portion of their power from resources they do not own or operate. Market prices for such supplies are quite volatile. In addition, utilities may face future customer switching to or from their supply service, especially if they are acting as provider of last resort (POLR). This problem is a blending of risk management with the traditional least-cost Integrated Resource Planning (IRP). Regulatory standards for findings of prudence in such a hybrid environment are

often not well understood or articulated, leaving utilities at risk for cost disallowances that can jeopardize their credit-worthiness. Mr. Graves has assisted several utilities in devising updated procurement mechanisms, hedging strategies, and associated regulatory guidelines that clarify the conditions for approval and cost recovery of resource plans, in order to make possible the expedited procurement of power from wholesale market suppliers.

- Public power authorities and cooperatives face risks from wholesale restructuring if their sales-for-resale customers are free to switch to or from supply contracting with other wholesale suppliers. Such switching can create difficulties in servicing the significant debt capitalization of these public power entities, as well as equitable problems with respect to non-switching customers. Mr. Graves has lead analyses of this problem, and has designed alternative product pricing, switching terms and conditions, and debt capitalization policies to cope with the risks.
- As a means of unbundling to retain ownership but not control of generation, some utilities turned to divesting output contracts. Mr. Graves was involved in the design and approval of such agreements for a utility's fleet of generation. The work entailed estimating and projecting cost functions that were likely to track the future marginal and total costs of the units and analysis of the financial risks the plant operator would bear from the output pricing formula. Testimony on risks under this form of restructuring was presented.
- Mr. Graves contributed to the design and pricing of unbundled services on several natural gas pipelines. To identify attractive alternatives, the marginal costs of possible changes in a pipeline's service mix were quantified by simulating the least-cost operating practices subject to the network's physical and contractual constraints. Such analysis helped one pipeline to justify a zone-based rate design for its firm transportation service. Another pipeline used this technique to demonstrate that unintended degradations of system performance and increased costs could ensue from certain proposed unbundling designs that were insensitive to system operations.
- For several natural gas pipeline companies, Mr. Graves evaluated the cost of equity capital in light of the requirements of FERC Order 636 to unbundle and reprice pipeline services. In addition to traditional DCF and risk positioning studies, the risk implications of different degrees of financial leverage (debt capitalization) were modeled and quantified. Aspects of rate design and cost allocation between services that also affect pipeline risk were considered.
- Mr. Graves assisted several utilities in forecasting market prices, revenues, and risks for generation assets being shifted from regulated cost recovery to competitive, deregulated wholesale power markets. Such studies have facilitated planning decisions, such as whether to divest generation or retain it, and they have been used as the basis for quantifying stranded costs associated with restructuring in regulatory hearings. Mr. Graves has assisted a leasing company with analyses of the tax-legitimacy of complex leasing transactions by reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the

buyer (lessor), the extent of defeasance, and compliance with prevailing guidelines for true-lease status.

Financial Analysis and Commercial Litigation

- Wildfires in California have become catastrophic in the past 5 years, creating both financial turmoil for the utilities and controversy over how to insure and manage this problem. Mr. Graves has been extensively involved in estimating the expected, growing cost of this problem and the design of mechanisms to insure it and compensate investors for the likelihood of uncompensated costs from fire damages.
- Despite well settled financial economics, there is great regulatory controversy surrounding how or whether to make adjustments in cost of capital measurements for differences in leverage between the proxy firms used to estimate the rate and the capital structure of the target utility. Mr. Graves has lead analyses of how to demonstrate the need for this adjustment, with testimony given to explain the foundations.
- For the government of Colombia, Mr. Graves testified in arbitration about misrepresentations that occurred in the negotiation of royalties over coal mining production. Those negotiations resulted in a royalty scheme that was much more favorable to the coal company than would have been acceptable to Colombia had more realistic representations occurred. He showed that the mining companies own studies projected much higher value and more favorable operating conditions for the facility, and that alternative schedules for running the mine would have produced more value than was asserted possible by its owners.
- For the co-owners of the SONGS nuclear power plant that had become inoperable due to failed and irreparable steam generators, Mr. Graves provided written and oral testimony in arbitration over what damages had been incurred by the utilities from having to replace the nuclear plant with new generation, purchased power, and transmission upgrades, as well as accelerated decommissioning liabilities. His report evaluated the impacts of the lost plant on the entire western power market, including how it would change the needs and costs for emission allowances in the California GHG market. He estimated that damages were nearly $7 billion dollars.
- For an international energy company seeking to expand its operations in the US, Mr. Graves lead an assessment of the market performance risks facing a possible acquisition target, in order to determine what contingencies or market shifts were critical to it being an attractive target. Uncertain long run wholesale energy conditions, tightening environmental regulations, and disruptive technology development prospects were considered.

- For an international technology firm that had experienced a recent bankruptcy, Mr. Graves assisted in the design of a study of how the remaining valuable assets could be deemed assignable to disparate country-specific claims. Company operating practices for research and development risk and profit sharing were evaluated to identify an equitable approach.
- For a merchant power company with a prematurely terminated development contract, Mr. Graves co-lead a team to value the lost contract. The contract included several different kinds of revenue streams of different risks, for which Brattle developed different discount rates and debt carrying-capacity assessments. The case was settled with a very large award consistent with the Brattle valuations.
- Holding company utilities with many subsidiaries in different states face differing kinds of regulatory allowances, balancing accounts with differing lags and allowed returns for cost recovery, possibly different capital structures, as well as different (and varying) operating conditions. Given such heterogeneity, it can be difficult to determine which subsidiaries are performing well vs. poorly relative to their regulatory and operational challenges. Mr. Graves developed a set of financial reporting normalization adjustments to isolate how much of each subsidiary's profitability was due to financial, vs. managerial, vs. non-recurring operational conditions, so that meaningful performance appraisal was possible.
- Many banks, insurance firms and capital management subsidiaries of large multinational corporations have entered into long term, cross border leases of properties under sale and leaseback or lease in, lease out terms. These have been deemed to be unacceptable tax shelters by the IRS, but that is an appealable claim. Mr. Graves has assisted several companies in evaluating whether their cross border leases had legitimate business purpose and economic substance, above and beyond their tax benefits, due to likelihood of potentially facing a role as equity holder with ownership risks and rewards. He has shown that this is a case-specific matter, not per se determined by the general character of these transactions.
- For a private energy hedge fund providing risk management contracts to industrial energy users, a breach of contract from one industrial customer was disputed as supposedly involving little or no loss because the fund had not been forced to liquidate positions at a loss that corresponded precisely to the abruptly terminated contract. Mr. Graves provided analysis demonstrating how the portfolio loss was borne, but other fund management metrics used to control positions, and other unrelated hedging positions, also changed roughly concurrently in a manner that disguised the way the economic damage was realized over time. The case was settled on favorable terms for Mr. Graves' client.
- Many utilities have regulated and unregulated subsidiaries, which face different types and degrees of risk. Mr. Graves lead a study of the appropriate adjustments to corporate hurdle rates for the various lines of business of a utility with many types of operations.
- A company that incurred Windfall Tax liabilities in the U.K. regarded those taxes as creditable against U.S. income taxes, but this was disputed by the IRS. Mr. Graves lead a team that prepared reports and testimony on why the Windfall Tax had the character of a

typical excess profits tax, and so should be deemed creditable in the U.S. The tax courts concurred with this opinion and allowed the claimed tax deductions in full.

- For a defendant in a sentencing hearing for securities' fraud, Mr. Graves prepared an analysis of how the defendant's role in the corporate crisis was confounded by other concurrent events and disclosures that made loss calculations unreliable. At trial, the Government stipulated that it agreed with Mr. Graves' analysis.
- For the U.S. Department of Justice, Mr. Graves prepared an event study quantifying bounds on the economic harm to shareholders that had likely ensued from revelations that Dynegy Corporation's "Project Alpha" had been improperly represented as a source of operating income rather than as a financing. The event study was presented in the re-sentencing hearing of Mr. Jamie Olis, the primary architect of Project Alpha.
- Mr. Graves has assisted leasing companies with analyses of the tax-legitimacy of complex leasing transactions. These analyses involved reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent, purpose and cost of defeasance, and compliance with prevailing guidelines for true-lease status.
- For a utility facing significant financial losses from likely future costs of its Provider of Last Resort (POLR) obligations, Mr. Graves prepared an analysis of how optimal hindsight coverage of the liability would have compared in costs to a proposed restructuring of the obligation. He also reviewed the prudence of prior, actual coverage of the obligation in light of conventional risk management practices and prevailing market conditions of credit constraints and low long-term liquidity.
- Several banks were accused of aiding and abetting Enron's fraudulent schemes and were sued for damages. Mr. Graves analyzed how the stock market had reacted to one bank's equity analyst's reports endorsing Enron as a "buy," to determine if those reports induced statistically significant positive abnormal returns. He showed that individually and collectively they did not have such an effect.
- Mr. Graves lead an analysis of whether a corporate subsidiary had been effectively under the strategic and operational control of its parent, to such an extent that it was appropriate to "pierce the corporate veil" of limited liability. The analysis investigated the presence of untenable debt capitalization in the subsidiary, overlapping management staff, the adherence to normal corporate governance protocols, and other kinds of evidence of excessive parental control.
- As a tax-revenue enhancement measure, the IRS was considering a plan to recapture deferred taxes associated with generation assets that were divested or reorganized during state restructurings for retail access. Mr. Graves prepared a white paper demonstrating the unfairness and adverse consequences of such a plan, which was instrumental in eliminating the proposal.

- For a major electronics and semiconductor firm, Mr. Graves critiqued and refined a proposed procedure for ranking the attractiveness of research and development projects. Aspects of risk peculiar to research projects were emphasized over the standards used for budgeting an already proven commercial venture.
- In a dispute over damages from a prematurely terminated long-term power tolling contract, Mr. Graves presented evidence on why calculating the present value of those damages required the use of two distinct discount rates: one (a low rate) for the revenues lost under the low-risk terminated contract and another, much higher rate, for the valuation of the replacement revenues in the risky, short-term wholesale power markets. The amount of damages was dramatically larger under a two-discount rate calculation, which was the position adopted by the court.
- The energy and telecom industries, especially in the late 1990s and early 2000s, were plagued by allegations regarding trading and accounting misrepresentations, such as wash trades, manipulations of mark-to-market valuations, premature recognition of revenues, and improper use of off-balance sheet entities. In many cases, this conduct has preceded financial collapse and subsequent shareholder suits. Mr. Graves lead research on accounting and financial evidence, including event studies of the stock price movements around the time of the contested practices, and reconstruction of accounting and economic justifications for the way asset values and revenues were recorded.
- Dramatic natural gas price increases in the U.S. have put several natural gas and electric utilities in the position of having to counter claims that they should have hedged more of their fuel supplies at times in the past. Mr. Graves developed testimony to rebut this hindsight criticism and risk management techniques for fuel (and power) procurement for utilities to apply in the future to avoid prudence challenges.
- As a means of calculating its stranded costs, a utility used a partial spin-off of its generation assets to a company that had a minority ownership from public shareholders. A dispute arose as to whether this minority ownership might be depressing the stock price, if a "control premium" was being implicitly deducted from its value. Using event studies and structural analyses, Mr. Graves identified the key drivers of value for this partially spun-off subsidiary, and he showed that value was not being impaired by the operating, financial and strategic restrictions on the company. He also reviewed the financial economics literature on empirical evidence for control premiums, which he showed reinforced the view that no control premium de-valuation was likely to be affecting the stock.
- A large public power agency was concerned about its debt capacity in light of increasing competitive pressures to allow its resale customers to use alternative suppliers. Mr. Graves lead a team that developed an Economic Balance Sheet representation of the agency's electric assets and liabilities in market value terms, which was analyzed across several scenarios to determine safe levels of debt financing. In addition, new service pricing and upstream supply contracting arrangements were identified to help reduce risks.

- Wholesale generating companies intuitively realize that there are considerable differences in the financial risk of different kinds of power plant projects, depending on fuel type, length and duration of power purchase agreements, and tightness of local markets. However, they often are unaware of how if at all to adjust the hurdle rates applied to valuation and development decisions. Mr. Graves lead a Brattle analysis of risk-adjusted discount rates for generation; very substantial adjustments were found to be necessary.
- A major telecommunications firm was concerned about when and how to reenter the Pacific Rim for wireless ventures following the economic collapse of that region in 1997-99. Mr. Graves lead an engagement to identify prospective local partners with a governance structure that made it unlikely for them to divert capital from the venture if markets went soft. He also helped specify contracting and financing structures that create incentives for the venture to remain together should it face financial distress, while offering strong returns under good performance.
- There are many risks associated with operations in a foreign country, related to the stability of its currency, its macro economy, its foreign investment policies, and even its political system. Mr. Graves has assisted firms facing these new dimensions to assess the risks, identify strategic advantages, and choose an appropriate, risk-adjusted hurdle rate for the market conditions and contracting terms they will face.
- The glut of generation capacity that helped usher in electric industry restructuring in the US led to asset devaluations in many places, even where no retail access was allowed. In some cases, this has led to bankruptcy, especially of a few large rural electric cooperatives. Mr. Graves assisted one such coop with its long term financial modeling and rate design under its plan of reorganization, which was approved. Testimony was provided on cost-of-service justifications for the new generation and transmission prices, as well as on risks to the plan from potential environmental liabilities.
- Power plants often provide a significant contribution to the property tax revenues of the townships where they are located. A common valuation policy for such assets has been that they are worth at least their book value, because that is the foundation for their cost recovery under cost-of-service utility ratemaking. However, restructuring throws away that guarantee, requiring reappraisal of these assets. Traditional valuation methods, e.g., based on the replacement costs of comparable assets, can be misleading because they do not consider market conditions. Mr. Graves testified on such matters on behalf of the owners of a small, out-of-market coal unit in Massachusetts.
- Stranded costs and out-of-market contracts from restructuring can affect municipalities and cooperatives as well as investor-owned utilities. Mr. Graves assisted one debt-financed utility in an evaluation of its possibilities for reorganization, refinancing, and re-engineering to improve financial health and to lower rates. Sale and leaseback of generation, fuel contract renegotiation, targeted downsizing, spin-off of transmission, and new marketing programs were among the many components of the proposed new business plan.

- As a means of reducing supply commitment risk, some utilities have solicited offers for power contracts that grant the right but not the obligation to take power at some future date at a predetermined price, in exchange for an initial option premium payment. Mr. Graves assisted several of these utilities in the development of valuation models for comparing the asking prices to fair market values for option contracts. In addition, he has helped these clients develop estimates of the critical option valuation parameters, such as trend, volatility, and correlations of the future prices of electric power and the various fuel indexes proposed for pricing the optional power.
- For the World Bank and several investor-owned electric utilities, Mr. Graves presented tutorial seminars on applying methods of financial economics to the evaluation of power production investments. Techniques for using option pricing to appraise the value of flexibility (such as arises from fuel switching capability or small plant size) were emphasized. He has applied these methods in estimating the value of contingent contract terms in fuel contracts (such as price caps and floors) for natural gas pipelines.
- Mr. Graves prepared a review of empirical evidence regarding the stock market's reaction to alternative dividend, stock repurchase, and stock dividend policies for a major electric utility. Tax effects, clientele shifting, signaling, and ability to sustain any new policies into the future were evaluated. A one-time stock repurchase, with careful announcement wording, was recommended.
- For a division of a large telecommunications firm, Mr. Graves assisted in a cost benchmarking study, in which the costs and management processes for billing, service order and inventory, and software development were compared to the practices of other affiliates and competitors. Unit costs were developed at a level far more detailed than the company normally tracked, and numerical measures of drivers that explained the structural and efficiency causes of variation in cost performance were identified. Potential costs savings of 10-50 percent were estimated, and procedures for better identification of inefficiencies were suggested.
- For an electric utility seeking to improve its plant maintenance program, Mr. Graves directed a study on the incremental value of a percentage point decrease in the expected forced outage rate at each plant owned and operated by the company. This defined an economic priority ladder for efforts to reduce outage that could be used in lieu of engineering standards for each plant's availability. The potential savings were compared to the costs of alternative schedules and contracting policies for preventive and reactive maintenance, in order to specify a cost reduction program.
- Mr. Graves conducted a study on the risk-adjusted discount rate appropriate to a publicly-owned electric utility's capacity planning. Since revenue requirements (the amounts being discounted) include operating costs in addition to capital recovery costs, the weighted average cost of capital for a comparable utility with traded securities may not be the correct rate for every alternative or scenario. The risks implicit in the utility's expansion alternatives were broken into component sources and phases, weighted, and compared to

the risks of bonds and stocks to estimate project-specific discount rates and their probable bounds.

Market Competition

- Mr. Graves assisted a nuclear plant owner with an assessment of whether a proposed merger of a company in whom it had a partial investment interest would alter the co-owner's incentives to manage the plant for maximum stand-alone value of the asset. Structural and behavioral models of the relevant market were developed to determine that there would be no material changes in incentive or ability to affect the value of the asset.
- Mr. Graves has testified on the quality of retail competition in Pennsylvania and on whether various proposals for altering Default Service might create more robust competition.
- Regulatory and legal approvals of utility mergers require evidence that the combined entity will not have undue market power. Mr. Graves assisted several utilities in evaluating the competitive impacts of potential mergers and acquisitions. He has identified ways in which transmission constraints reduce the number and type of suppliers, along with mechanisms for incorporating physical flow limits in FERC's Delivered Price Test (DPT) for mergers. He has also assessed the adequacy of mitigation measures (divestitures and conduct restrictions) under the DPT, Market-Based Rates, and other tests of potential market power arising from proposed mergers.
- A major concern associated with electric utility industry restructuring is whether or not generation markets are adequately competitive. Because of the state-dependent nature of transmission transfer capability between regions, itself a function of generation use, the quality of competition in the wholesale generation markets can vary significantly and may be susceptible to market power abuse by dominant suppliers. Mr. Graves helped one of the largest ISOs in the U.S. develop market monitoring procedures to detect and discourage market manipulations that would impair competition.
- Vertical market power arises when sufficient control of an upstream market creates a competitive advantage in a downstream market. It is possible for this problem to arise in power supply, in settings where the likely marginal generation is dependent on very few fuel suppliers who also have economic interests in the local generation market. Mr. Graves analyzed this problem in the context of the California gas and electric markets and filed testimony to explain the magnitude and manifestations of the problem.
- The increased use of transmission congestion pricing has created interest in merchant transmission facilities. Mr. Graves assisted a developer with testimony on the potential impacts of a proposed line on market competition for transmission services and adjacent generation markets. He also assisted in the design of the process for soliciting and ranking bids to buy tranches of capacity over the line.
- Many regions have misgivings about whether the preconditions for retail electric access are truly in place. In one such region, Mr. Graves assisted a group of industrial customers with a critique of retail restructuring proposals to demonstrate that the locally weak

transmission grid made adequate competition among numerous generation suppliers very implausible.

- Mr. Graves assisted one of the early ISOs with its initial market performance assessment and its design of market monitoring tests for diagnosing the quality of prevailing competition.

Electric and Gas Transmission

- Substantial fleets of wind-based generation can impose significant integration costs on power systems. Mr. Graves assisted in assessing what additional amounts and costs for ancillary services would be needed for a Western utility with a large renewable fleet. The approach included a statistical analysis of how wind output was correlated with demand, and how much forecasting error in wind output was likely to be faced over different scheduling horizons. Benefits of geographic diversity of the wind fleet were also assessed.
- For a utility seeking FERC approval for the purchase of an affiliate's generating facility, Mr. Graves analyzed how transmission constraints affecting alternative supply resources altered their usefulness to the buyer.
- As part of a generation capacity planning study, he lead an analysis of how congestion premiums and discounts relative to locational marginal prices (LMPs) at load centers affected the attractiveness of different potential locations for new generation. At issue was whether the prevailing LMP differences would be stable over time, as new transmission facilities were completed, and whether new plants could exacerbate existing differentials and lead to degraded market value at other plants.
- Mr. Graves assisted a genco with its involvement in the negotiation and settlement of "regional through and out rates" (RTOR) that were to be abolished when MISO joined PJM. His team analyzed the distribution of cost impacts from several competing proposals, and they commented on administrative difficulties or advantages associated with each.
- For the electric utility regulatory commission of Colombia, S.A., Mr. Graves led a study to assess the inadequacies in the physical capabilities and economic incentives to manage voltages at adequate levels. The Brattle team developed minimum reactive power support obligations and supplement reactive power acquisition mechanisms for generators, transmission companies, and distribution companies.
- Mr. Graves conducted a cost-of-service analysis for the pricing of ancillary services provided by the New York Power Authority.
- On behalf of the Electric Power Research Institute (EPRI), Mr. Graves wrote a primer on how to define and measure the cost of electric utility transmission services for better planning, pricing, and regulatory policies. The text covers the basic electrical engineering of power circuits, utility practices to exploit transmission economies of scale, means of assuring system stability, economic dispatch subject to transmission constraints, and the

estimation of marginal costs of transmission. The implications for a variety of policy issues are also discussed.

- The natural gas pipeline industry is wedged between competitive gas production and competitive resale of gas delivered to end users. In principle, the resulting basis differentials between locations around the pipeline ought to provide efficient usage and expansion signals, but traditional pricing rules prevent the pipeline companies from participating in the marginal value of their own services. Mr. Graves worked to develop alternative pricing mechanisms and service mixes for pipelines that would provide more dynamically efficient signals and incentives.
- Mr. Graves analyzed the spatial and temporal patterns of marginal costs on gas and electric utility transmission networks using optimization models of production costs and network flows. These results were used by one natural gas transmission company to design receipt-point-based transmission service tariffs, and by another to demonstrate the incremental costs and uneven distribution of impacts on customers that would result from a proposed unbundling of services.

TESTIMONY

On behalf of Public Service Company of New Mexico, presented testimony before the New Mexico Public Regulation Commission on the merits of replacing the San Juan Generating Station coal units with a fleet of renewables, storage and gas-fired peakers, and on the reasons for appropriateness of allowing full recovery of sunk costs despite early retirement. Case No. 19-00018-UT, November 15, 2019.

On behalf of both Southern California Edison and Pacific Gas & Electric Company, presented direct and rebuttal testimony co-authored with Robert Mudge in regard to cost of wildfire risk under AB 1054, a state policy to create a fire insurance mechanism. Applications 19-04-014 and 19-04-015, September 4, 2019.

For Nicor Gas, a natural gas distribution company, Mr. Graves co-authored testimony on the cost of equity capital utilizing a broad spectrum of risk-pricing methods and explaining how financial leverage affects it. Testimony was filed with the Illinois Commerce Commission, Docket 18-xxxx, November 9, 2018.

For the electric transmission division of Pacific Gas & Electric, Mr. Graves presented testimony and co-authored an accompanying report on the cost of capital impacts from the extreme risks arising from potential liability for damages caused by large wildfires in California. Testimony before the FERC, Docket ER19- ___ - 000, Exhibit PGE-0019, October 1, 2018.

For the Government of Colombia, written and oral testimony in regard to apparent misrepresentations of coal mine development costs and expected profitability by Glencore Corporation that adversely affected royalty payments for Colombia. Heard in the International Court of Arbitration, ICSID Case No ARB/16/6, Washington DC, June 2018.

Before the Pennsylvania Public Utility Commission, written direct testimony for Philadelphia Gas Works, Docket No. R-2017-2586783, June 2017, regarding financial benchmarking of the company vs. investor owned and public agency peers, and the need for a rate increase to maintain financial metrics and cover future costs.

Direct testimony in regard to a claim for a share of lime consumption reduction costs obtained by Plum Point as one of SMEPA's power plant operator/suppliers, on behalf of SMEPA, before the American Arbitration Association in the matter of Southwest Mississippi Electric Power Association vs. Plum Point Energy Associates, Case No. 01-15-0002-6062, September 2016.

Direct, Rebuttal and Supplementary Rebuttal reports regarding damages from loss of a nuclear generation facility, on behalf of Southern California Edison Company, Edison Material Supply LLC., San Diego Gas and Electric Company and City of Riverside before the International Chamber of Commerce in the matter of Southern California Edison v. Mitsubishi Nuclear Energy Systems, Inc. and Mitsubishi Heavy Industries, Ltd., Case No. 19784/AGF/RD, July 27, 2015 (direct), January 19, 2016 (rebuttal) and March 14, 2016 (supplemental).

Direct report re determination of an appropriate level of return needed for Standard Offer Service (SOS), on behalf of Delmarva Power & Light Company and Potomac Electric Power Company before the Maryland Public Service, Case Nos. 9226 and 9232, July 24, 2015.

Direct testimony in regard to the prudence of its gas hedging, on behalf of Hope Gas, Inc., before the West Virginia Public Service Commission, Case No. 12-1070-G-30C, June 24, 2013.

Direct testimony on behalf of Public Service Company of New Mexico before the NM Public Regulation Commission re appropriate profit incentives for energy conservation activities, Case No. 12-00317-UT, October 5, 2012.

Rebuttal testimony on behalf of Rocky Mountain Power Company before the Public Service Commission of Utah in regard to hedging practices for natural gas supply, Docket 11-035-200, July 2012.

Rebuttal testimony on behalf of Rocky Mountain Power Company before the Public Service Commission of Wyoming in regard to gas supply hedging and loss-sharing, Docket No. 20000-405-ER-11, June 2012.

Direct testimony on behalf of Ohio Power Company before the PUC of Ohio in regard to performance of PJM capacity markets, in Ohio Power's application for its ESP service charges, Case No. 10-2929-EL-UNC, March 30, 2012.

Expert report and oral testimony on behalf of Pepco Holdings, Inc. before the Maryland Public Service Commission in regard to inadequacies in the MD PSC's RFP for new combined cycle generation development in SWMAAC, Case No. 9214, January 31, 2012.

Direct testimony on behalf of Columbus Southern Power Company and Ohio Power Company before the Public Utilities Commission of Ohio in the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company, Case No. 10-2929 -EL-UNC, August 31, 2011.

Rebuttal report on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 07-876C, No. 07-875C, No. 07-877C, August 5, 2011.

Direct Testimony on rehearing regarding the allowance of swaps in Rocky Mountain Power's fuel adjustment cost recovery mechanism, on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, July 2011.

Comments and Reply Comments on capacity procurement and transmission planning on behalf of New Jersey Electric Distribution Companies before the State of New Jersey Board of Public Utilities in the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning, NJ BPU Docket No. EO11050309, June 17, 2011; July 12, 2011.

Rebuttal testimony regarding Rocky Mountain Power's hedging practices on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, Docket No. 10-035-124, June 2011.

Expert and Rebuttal reports regarding contract termination damages, on behalf of Hess Corporation before the United States District Court for the Northern District of New York, Case No. 5:10-cv-587 (NPM/GHL), April 29, 2011, May 13, 2011.

Expert and Rebuttal reports on spent fuel removal at Rancho Seco nuclear power plant, on behalf of Sacramento Municipal Utility District before the U.S. Court of Federal Claims, No. 09-587C, October 2010, July 1, 2011.

Rebuttal testimony on the Impacts of the Merger with First Energy on retail electric competition in Pennsylvania, on behalf of Allegheny Power before the Pennsylvania Public Utility Commission, Docket Nos. A-2010-2176520 and A-2010-2176732, September 13, 2010.

Expert and Rebuttal reports on the interpretation of pricing terms in a long term power purchase agreement, on behalf of Chambers Cogeneration Limited Partnership before the Superior Court of New Jersey, Docket No. L-329-08, August 23, 2010, September 21, 2010.

Expert and Rebuttal reports on spent fuel removal at Trojan nuclear facility, on behalf of Portland General Electric Company, The City of Eugene, Oregon, and PacifiCorp before the United States Court of Federal Claims No. 04-0009C, August 2010, June 29, 2011.

Rebuttal and Rejoinder testimonies on the approval of its Smart Meter Technology Procurement and Installation Plan before the Pennsylvania Public Utility Commission on behalf of West Penn Power Company d/b/a Allegheny Power, Docket No. M-2009-2123951, October 27, 2009, November 6, 2009.

Supplemental Direct testimony on the need for an energy cost adjustment mechanism in Utah to recover the costs of fuel and purchased power, on behalf of Rocky Mountain Power before the Public Service Commission of Utah, Docket No. 09-035-15, August 2009.

Expert and Rebuttal reports on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 98-126C, No. 98-154C, No. 98-474C, April 24, 2009, July 20, 2009.

Expert report in regard to opportunistic under-collateralization of affiliated trading companies, on behalf of BJ Energy, LLC, Franklin Power LLC, GLE Trading LLC, Ocean Power LLC, Pillar Fund LLC and Accord Energy, LLC before the United States District Court for the Eastern District of Pennsylvania, No. 09-CV-3649-NS, March 2009.

Rebuttal report in regard to appropriate discount rates for different phases of long-term leveraged leases, on behalf of Wells Fargo & Co. and subsidiaries, Docket No. 06-628T, January 15, 2009.

Oral and written direct testimony regarding resource procurement and portfolio design for Standard Offer Service, on behalf of PEPCo Holdings Inc. in its Response to Maryland Public Service Commission, Case No. 9117, October 1, 2008 and December 15, 2008.

Direct testimony regarding considerations affecting the market price of generation service for Standard Service Offer (SSO) customers, on behalf of Ohio Edison Company, et al., Docket 08-125, July 24, 2008.

Direct testimony in support of Delmarva's "Application for the Approval of Land-Based Wind Contracts as a Supply Source for Standard Offer Service Customers," on behalf of Delmarva Power & Light Company before the Public Service Commission of Delaware, July 24, 2008.

Oral direct testimony in regard to the Government's performance in accepting spent nuclear fuel under contractual obligations established in 1983, on behalf of plaintiff Dairyland Power Cooperative before the United States Court of Federal Claims (No. 04-106C), July 17, 2008.

Direct testimony for Delmarva Power & Light on risk characteristics of a possible managed portfolio for Standard Offer Service, as part of Delmarva's IRP filings (PSC Docket No. 07-20), March 20, 2008 and May 15, 2008.

Oral direct testimony regarding the economic substance of a cross-border lease-to-service contract for a German waste-to-energy plant on behalf of AWG Leasing Trust and KSP Investments, Inc before U. S. District Court, Northern District of Ohio, Eastern Division, Case No. 1:07CV0857, January 2008.

Expert report (October 15, 2007) and oral testimony (September 21 and 22, 2010) in Commonwealth of Pennsylvania Department of Environmental Protection, et al., v. Allegheny Energy Inc, et al. regarding flaws in the plaintiffs' assessment of emissions attributed to repairs at certain power plants, Civil Action No, 2:05ev1885.

Direct testimony regarding portfolio management alternatives for supplying Standard Offer Service, on behalf of Potomac Electric Power Company and Delmarva Power & Light Company before the Public Service Commission of Maryland, Case No. 9117, September 14, 2007.

Direct testimony in regard to preconditions for effective retail electric competition, on behalf of New West Energy Corporation before the Arizona Commerce Commission, Docket No. E-03964A-06-0168, August 31, 2007.

Direct and rebuttal testimonies regarding the application of OG&E for an order of commission granting preapproval to construct Red Rock Generating Facility and authorizing a recovery rider, on behalf of Oklahoma Gas & Electric Company (OG&E) before the Corporation Commission of the State of Oklahoma, Case No. PUD 200700012, January 17, 2007 and June 18, 2007.

Testimony in regard to whether defendant's role in accounting misrepresentations could be reliably associated with losses to shareholders, on behalf of defendant Mark Kaiser before U.S. District Court of New York SI:04Cr733 (TPG).

Rebuttal testimony on proposed benchmarks for evaluating the Illinois retail supply auctions, on behalf of Midwest Generation EME L.L.C. and Edison Mission Marketing and Trading before the Illinois Commerce Commission Docket No. 06-0800, April 6, 2007.

Direct and rebuttal testimonies on the shareholder impacts of Dynegy's Project Alpha for the sentencing of Jamie Olis, on behalf of the U.S. Department of Justice before the United States District Court, Southern District of Texas, Houston Division, Criminal No. H-03-217, September 12, 2006.

Direct and rebuttal testimony on the need for POLR rate cap relief for Metropolitan Edison and Pennsylvania Electric and the prudence of their past supply procurement for those obligations, on behalf of FirstEnergy Corp before the Pennsylvania Public Utility Commission, Docket Nos. R-00061366 and R-00061367, August 24, 2006.

Direct testimony regarding Deutsche Bank Entities' opposition to Enron Corp's amended motion for class certification, on behalf of the Deutsche Bank Entities before the United States District Court, Southern District of Texas, Houston Division, Docket No. H-01-3624, February 2006.

Expert and Rebuttal reports regarding the non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract, on behalf of Pacific Gas and Electric Company before the United States Court of Federal Claims, Docket No. 04-0074C, into which has been consolidated No. 04-0075C, November 2005.

Direct testimony regarding the appropriate load caps for a POLR auction, on behalf of Midwest Generation EME, LLC before the Illinois Commerce Commission, Docket No. 05-0159, June 8, 2005.

Affidavit regarding unmitigated market power arising from the proposed Exelon—PSEG Merger, on behalf of Dominion Energy, Inc. before the Federal Energy Regulatory Commission, Docket No. EC05-43-000, April 11, 2005.

Expert and rebuttal reports and oral testimonies before the American Arbitration Association on behalf of Liberty Electric Power, LLC, Case No. 70 198 4 00228 04, December 2004, regarding damages under termination of a long-term tolling contract.

Oral direct and rebuttal testimony before the United States Court of Federal Claims on behalf of Connecticut Yankee Atomic Power Company, Docket No. 98-154 C, July 2004 (direct) and August 2004 (rebuttal), regarding non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract.

Direct, supplemental and rebuttal testimony before the Public Service Commission of Wisconsin, on behalf of Wisconsin Public Service Corporation and Wisconsin Power and Light Company, Docket No. 05-EI-136, February 27, 2004 (direct), May 4, 2004 (supplemental) and May 28, 2004 (rebuttal) in regard to the benefits of the proposed sale of the Kewaunee nuclear power plant.

Testimony before the Public Utility Commission of Texas on behalf of CenterPoint Energy Houston Electric LLC, Reliant Energy Retail Services LLC, and Texas Genco LP, Docket No. 29526, March 2004 (direct) and June 2004 (rebuttal), in regard to the effect of Genco separation agreements and financial practices on stranded costs and on the value of control premiums implicit in Texas Genco Stock price.

Rebuttal and additional testimony before the Illinois Commerce Commission, on behalf of Peoples Gas Light and Coke Company, Docket No. 01-0707, November 2003 (rebuttal) and January 2005 (additional rebuttal), in regard to prudence of gas contracting and hedging practices.

Rebuttal testimony before the State Office of Administrative Hearings on behalf of Texas Genco and CenterPoint Energy, Docket No. 473-02-3473, October 23, 2003, regarding proposed exclusion of part of CenterPoint's purchased power costs on grounds of including "imputed capacity" payments in price.

Rebuttal testimony before the Federal Energy Regulatory Commission (FERC) on behalf of Ameren Energy Generating Company and Union Electric Company, Docket No. EC03-53-000, October 6, 2003, in regard to evaluation of transmission limitations and generator responsiveness in generation procurement.

Rebuttal testimony before the New Jersey Board of Public Utilities on behalf of Jersey Central Power & Light Company, Docket No. ER02080507, March 5, 2003, regarding the prudence of JCP&L's power purchasing strategy to cover its provider-of-last-resort obligation.

Oral testimony (February 17, 2003) and expert report (April 1, 2002) before the United States District Court, Southern District of Ohio, Eastern Division on behalf of Ohio Edison Company and Pennsylvania Power Company, Civil Action No. C2-99-1181, regarding coal plant maintenance projects alleged to trigger New Source Review.

Expert Report before the United States District Court on behalf of Duke Energy Corporation, Docket No. 1:00CV1262, September 16, 2002, regarding forecasting changes in air pollutant emissions following coal plant maintenance projects.

Direct testimony before the Public Utility Commission of Texas on behalf of Reliant Energy, Inc., Docket No. 26195, July 2002, regarding the appropriateness of Reliant HL&P's gas contracting, purchasing and risk management practices, and standards for assessing HL&P's gas purchases.

Direct and rebuttal testimonies before the Public Utilities Commission of the State of California on behalf of Southern California Edison, Application No. R. 01-10-024, May 1, 2002, and June 5, 2002, regarding Edison's proposed power procurement and risk management strategy, and the regulatory guidelines for reviewing its procurement purchases.

Rebuttal testimony before the Texas Public Utility Commission on behalf of Reliant Resources, Inc., Docket No. 24190, October 10, 2001, regarding the good-cause exception to the substantive rules that Reliant Resources, Inc. and the staff of the Public Utility Commission sought in their Provider of Last Resort settlement agreement.

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Docket No. UE 374
Exhibit PAC/602
Witness: Frank Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Frank Graves

Review of PCAM Implementation in Other States

February 2020

Review of PCAM Implementation in Other States

State	Deadband	Risk Sharing	SNL Description of Adjustment Clause
Alabama			Alabama Power, Spire Alabama and Spire Gulf are regulated under Rate Stabilization and Equalization frameworks that adjust base rates periodically (see the Alternative regulation section). The tariffs of the major energy utilities include adjustment provisions to allow for recovery of changes in income taxes and certain general and local taxes. An Energy Cost Recovery, or ECR, mechanism is also in place for Alabama Power. The ECR mechanism is established on the basis of estimates of electric sales, fuel-related costs, and purchased power costs, and reflects accumulated over- or underrecovered amounts.
Alaska			Electric fuel and gas commodity costs are recovered through mechanisms that are separate from base distribution rates. Alaska Electric Light and Power Co. utilizes a power cost adjustment that is updated quarterly. ENSTAR Natural Gas Co.'s gas cost adjustment is updated annually; both are subject to true-up.
Arizona		Yes. **APS'** PSA is subject to a $0.004/kWh annual cap on rate increases or decreases, unless the base cost of fuel and purchased power is reset.	Arizona Public Service Co., or APS, utilizes a Power Supply Adjustor, or PSA, a mechanism that permits the deferral and recovery of fuel and purchased power costs, certain production-related variable costs, and certain energy storage costs outside of a rate case. The PSA is subject to a $0.004/kWh annual cap on rate increases or decreases, unless the base cost of fuel and purchased power is reset. The PSA incorporates a forward-looking estimate of fuel and purchased power costs to set a rate that is subsequently reconciled with actual costs. The PSA consists of three components: the "forward component" that recovers or refunds differences between expected fuel and purchased power costs and those reflected in base rates; the "historical component," which tracks the differences between actual costs and those recovered through the combination of base rates and the forward component; and the "transition component," which provides for the recovery or refund of deferred balances stemming from the operation of the old PSA. The PSA also reflects margins from the sale of emissions allowances. Tucson Electric Power Co., or TEP, utilizes a purchased power and fuel adjustment clause, or PPFAC. The PPFAC includes a forward-looking component. A PPFAC is also in place for UNS Electric Inc., or UNS-E.
Arkansas			State statutes permit the electric utilities to request PSC approval of mechanisms that allow the recovery of costs related to fuel and purchased power, energy efficiency, purchased gas and certain other items. Energy cost recovery, or ECR, riders — Electric utilities recover fuel and purchased power costs through an ECR rider. The ECR rider is calculated annually, reflecting the actual cost in the previous calendar year, with an adjustment for projected changes. ECR rate changes are implemented automatically; however, a utility's ECR rider calculation is subject to a 15-day review period. The staff is permitted to audit any utility's ECR rider and can recommend adjustments to the ECR rate filed by the company.
California			The state's major electric utilities utilize a balancing account, the energy resource recovery account, or ERRA, that is designed to track and allow recovery of the difference between electric procurement costs included in rates and actual costs incurred under each utility's procurement plan. The PUC must review the revenues and costs associated with each utility's electricity procurement plan at least annually and adjust retail electricity rates or order refunds as appropriate, typically once a year. In addition, rate changes can be implemented based on the ERRA trigger mechanism, which is effective when aggregate over-collections or undercollections exceed 5% of the utility's prior-year electric generation revenues, excluding amounts collected for the Department of Water Resources. The PUC would make the final determination of an ERRA trigger mechanism rate change.
Colorado			Public Service Company of Colorado's, or PSCO's, fuel and purchased energy costs are recovered through an incentive based electric commodity adjustment, or ECA, that compares actual fuel and purchased power expenses to a formula based benchmark. The ECA also contains certain earnings-sharing provisions related to energy trading activities (see the Alternative Regulation section). PSCO utilizes a purchased capacity cost adjustment clause that allows for recovery of the costs of purchased power not included in base rates or other recovery mechanisms. Black Hills Colorado Electric Utility Company, or BHCE, is subject to an energy cost adjustment mechanism under which all fuel and purchased energy cost differences from the company's base energy cost rate are fully recovered from, or credited to, customers. The impacts of certain incentive mechanisms also flow through the mechanism.

State	Deadband	Risk Sharing	SNL Description of Adjustment Clause
Florida			The fuel cost recovery clause, or FCRC, and the capacity cost recovery clause, or CCRC, provide for recovery of prudently incurred fuel and purchased power costs, respectively. Annual fuel factors are established based upon 12-month projections of fuel costs and energy purchases and sales. Hearings are held each November, during which the PSC sets fuel factors for the next calendar year. Subsequent to the November hearings, utilities may seek or the PSC may require a midterm modification to the factors if updated projected costs for the year vary from updated projected revenues by plus or minus 10%. Interest is accrued on both over- and under-recovered balances. Included in the FCRC is a generating performance incentive factor that provides a financial reward or penalty when a company's base load generating units' availability and heat rate vary from targets approved by the PSC. The reward or penalty is limited to a 25-basis point ROE spread. The PSC generally requires market-based pricing of coal purchased from an affiliate. The FCRC also reflects gains from non-firm energy sales. A three-year moving average based on eligible sales is determined, and 100% of the sales up to this benchmark are credited to ratepayers. For sales above the benchmark, 80% of the gains accrue to ratepayers, with 20% retained by Duke Energy Florida LLC, Tampa Electric Co. Company, or TEC, and Gulf Power Co
Georgia			A non-automatic fuel adjustment mechanism, known as the fuel cost recovery clause, is in place for Georgia Power, or GP. Hearings are required before increases or decreases are implemented. Electric fuel rates are based on estimated sales and fuel costs, and any balance of previously unrecovered/over-recovered fuel costs is considered in setting new rates. The energy portion of purchased power transactions is reflected in the mechanism; the capacity component is recovered through base rates. The cost of GP's natural gas and oil procurement hedging program, including any net gains or losses, are also recovered through the fuel cost recovery clause.
Hawaii		Yes. **Hawaiian Electric Companies** recover 98% of fuel cost fluctuations from customers and incur 2% (with utility exposure capped at $2.5 million)	Fuel adjustment clauses are in place for electric utilities. The clauses are adjusted monthly for changes in fuel costs and the fuel-cost component of purchased energy, and for variations from the forecasted generation mix. Hawaiian Electric Company's, or HECO's, purchased power adjustment clause, or PPAC, is designed to recover purchased power capacity costs and the O&M expense component of purchased power energy costs. Similar mechanisms are in place for Hawaii Electric Light Company, or HELCO, and Maui Electric Company, or MECO. Rates under the PPAC mechanisms are adjusted monthly,
Idaho		Yes. **Avista's** PCA enables the company to defer 90% of net power cost deviations, similar to **PacifiCorp. Idaho Power**'s PCA includes a 95% sharing mechanism	Electric power cost adjustment (PCA) mechanisms are utilized by Avista Corporation, Idaho Power (IP), and PacifiCorp. Semi-automatic purchased gas adjustments are utilized by Avista and Intermountain Gas. Electric and gas utilities may seek PUC approval to issue energy cost recovery (securitization) bonds to moderate the impact of power cost increases on customers (see the Securitization section). Avista's PCA enables the company to defer, in a balancing account, 90% of the difference between actual net power costs and the amount included in retail rates. IP has a similar mechanism in place with a sharing provision under which annual rate adjustments reflect 95% of the cost variations associated with water supply for hydro-electric production, wholesale energy prices, and retail load changes. An energy cost adjustment mechanism is in place for PacifiCorp that allows for the recovery of 90% of the difference between actual power costs and those included in rates.
Indiana			FAC proceedings Electric utilities may adjust rates for changes in fuel and purchased power — energy component only — costs generally every three months, following hearings, through the FAC. The FAC is based on estimated costs of fuel and purchased power for a future three-month period, with an additional factor to account for over- or under recoveries caused by variances between estimated and actual costs in the previous three-month period. No carrying charges accrue on over- or under-recoveries. The adjustment factor may be modified more frequently than every three months under emergency circumstances. By law, the URC may not approve an FAC rate adjustment if it will result in the utility earning a net operating income, or NOI, in excess of that authorized.
Iowa			Energy adjustment clauses, or EACs, are modified monthly based on forecast energy costs and fuel and purchased power for two months. The capacity/demand portions of purchased power are recovered through base rates. Under- and over-recoveries are deferred and respectively charged and credited to customers in the succeeding months. Interstate Power and Light Co., or IP&L, uses an EAC that provides for recovery of fuel and purchased power costs as well as revenues and costs associated with sales or purchases of emission allowances. MidAmerican Energy Co. uses an EAC that excludes chemical-related costs.

State	Deadband	Risk Sharing	SNL Description of Adjustment Clause
Missouri		Yes. **Empire District Electric Co, Kansas City Power and Light,** and **Union Electric** can all recover 95% of fuel and purchased power costs, net emissions allowance costs and OSS revenues that vary from levels included in base rates.	Empire District Electric Co. utilizes an FAC that provides for the company to recover from/flow to ratepayers, on a semi-annual basis over six-month recovery periods, 95% of incremental variations in "prudently incurred" fuel and purchased power costs, net emissions allowance costs and OSS revenues from the levels included in base rates. In a 2015 rate case decision, the PSC required that a portion of the transmission costs Empire incurs related to its participation in the Southwest Power Pool, or SPP, market be excluded from its FAC [...] Union Electric Co., or UE, utilizes an FAC that provides for the company to recover from/flow to ratepayers 95% of incremental variations in prudently incurred fuel and purchased power costs, net emissions allowances and OSS revenues from the levels included in base rates. UE's FAC incorporates three adjustments per year and eight-month-long recovery periods [...] In a 2015 rate case decision, the PSC authorized Kansas City Power and Light Co., or KCP&L, to implement an FAC that provides for the company to recover from/flow to ratepayers 95% of incremental variations in prudently incurred fuel and purchased power costs, net emissions allowances and OSS revenues from the levels included in base rates. KCP&L's FAC incorporates two adjustments per year and 12-month recovery periods.
Montana		Yes. **NorthWestern Energy** and **MDU Resources Group** both have power cost adjustment mechanisms that include a 90% rate payers/10% shareholders cost share	On July 14, 2017, NorthWestern filed its Power Costs and Credits Adjustment Mechanism, or PCCAM, proposal with the commission. The proposed PCCAM provides for annual adjustments based on 12 months of actual data, and provides of a 90%/10% allocation between rate payers and shareholders of the related costs. The PCCAM would temporarily apply to Demand Side Management program costs and certain administrative and general costs until future treatment is determined as part of NorthWestern's next general electric rate case. The commission is expected to hold a hearing on the matter on May 31, 2018. MDU Resources Group utilizes a monthly-adjusted fuel and purchased power cost adjustment mechanism that contains certain incentive provisions, including a 90%/10% sharing of the costs reflected in the mechanism.
Nevada			Electric utilities are subject to a deferred energy cost recognition procedure, under which Commission approval is required prior to implementation of changes in the recovery of fuel and purchased power costs. In accordance with this procedure, Nevada Power Company, or NPC, and Sierra Pacific Power Company, or SPP, file quarterly deferred energy adjustment applications, or DEAAs, proposing to recover or refund the deferred balances, representing the difference between actual fuel and purchased power costs incurred and the amounts currently reflected in rates. Electric utilities must reset, on a quarterly basis, the rate for ongoing fuel and purchased power costs, referred to as the base tariff energy rate, or BTER. The quarterly reset is designed to reflect power costs on a more current basis, thereby eliminating large deferred energy balances. These quarterly BTER adjustments are reviewed annually by the PUC as part of the companies' DEAA filings. Costs eligible for recovery include all prudent expenses incurred to purchase fuel, capacity, and energy, as well as the carrying charges on deferred balances. The burden of proof regarding prudence rests with the utility.
New Mexico			Commission rules provide for automatic fuel adjustment clauses; the fuel and purchased power cost adjustment clause, or FPPCAC, for an electric utility is calculated monthly, but a variance from monthly reporting may be sought. The FPPAC includes a balancing account in which there is approximately a two-month collection lag. A utility is required to reapply for continuation of an FPPCAC every four years, at which time a comprehensive review of the clause is undertaken. In 2008, the PRC authorized Public Service Co. of New Mexico, or PSNM, to establish an emergency FPPCAC. The clause contained several conditions, including that the recoverable costs were subject to a prudence review. PSNM's FPPCAC had been eliminated in 1994, following a stipulation. In 2009, the PRC adopted a rate case settlement that included the reinstatement of the company's FPPCAC on a permanent basis. The fuel factor is adjusted annually. Additionally, the approved settlement contained an SO2 rider through which customers are credited with their share of revenues from allowance sales. El Paso Electric Co., or EPE, may seek approval to adjust its FPPCAC if the company experiences an over- or under-recovery balance of at least $2 million of fuel and purchase power expenses as of Dec. 31 and June 30 of each year. Southwestern Public Service Co., or SWPS, uses an FPPCAC under which it may petition for a change in the fuel factor if the over/under-recovery balance reaches $5 million.
North Carolina			Prudent electric fuel and fuel-related costs are recoverable through a fuel adjustment clause, or FAC. Each utility has an annual hearing to review fuel costs, with a test period determined by the NCUC for each company. The proceedings provide for a true up of any over or undercollections from the previous year, with interest included only for overcollections. The costs of certain reagents used in reducing or treating emissions, as well as certain nonfuel purchased power costs for economic purchases, may be recovered through the FAC. The law limits the annual increase in recoverable costs related to certain purchased power contracts to 2% of a utility's total retail revenues.

State	Deadband	Risk Sharing	SNL Description of Adjustment Clause
North Dakota			Mechanisms that provide for automatic recognition of changes in fuel and the energy portion of purchased power costs are in place for Northern States Power, or NSP, MDU Resources Group and Otter Tail Power, or OTP. Fuel and purchased power cost adjustments are implemented monthly and are based on a rolling four-month history. There is generally a two-month lag for recovery. MDU also recovers capacity costs associated with purchased power through its fuel and purchased power adjustment clause.
Oklahoma			Fully automatic electric FACs are prohibited in Oklahoma. However, semi-automatic FACs are in place. Utilities may propose a change in the current FAC billing factor according to each company's Commission-approved FAC tariff. Once the utility files for a change in its FAC rate, the staff has five days within which to respond. If the staff files objections to the change, a formal investigation is initiated; if the staff files no objections, the proposed rates become effective. The historic costs and revenues included in the FAC are reviewed by the OCC after each calendar year for accuracy and prudence. Oklahoma Gas & Electric Co.'s, or OG&E's, FAC is typically adjusted semi-annually but can be adjusted quarterly if costs have changed and are expected to remain at their current levels for the foreseeable future or if the monthly over or undercollected FAC amounts for a given period are greater than 5% of the company's projected annual Oklahoma-jurisdictional fuel costs. Purchased power and certain cogeneration and capacity payment differentials are reflected in the FAC. OG&E also recovers a portion of the transportation costs associated with gas deliveries to its generating facilities through the FAC. Public Service Co. of Oklahoma's, or PSO's, FAC is adjusted annually, subject to a cap on under and overrecoveries. However, an immediate adjustment may be implemented if the under or overrecovered balance exceeds $50 million. Otherwise, amounts that differ from the levels reflected in base rates are deferred in a balancing account, and the deferrals are recovered over the subsequent 12 months. The FAC also allows for current recovery of line losses above or below the amount recognized in PSO's base rates. Such under or overrecoveries are recovered from, or refunded to, customers during subsequent months. Ratepayers' 90% share of off system sales margins flow through PSO's FAC.
Oregon	Yes, **PGE** and **PacifiCorp** have a -$15 to $30 million deadband, while **Idaho Power's** costs/savings are reduced by a deadband of 250/125 ROE basis points	Yes. PCAMs for **PGE, PacifiCorp,** and **Idaho Power** all recover 90% of cost deviations outside of a deadband	Portland General Electric, or PGE, PacifiCorp, and Idaho Power, or IP are permitted to annually adjust rates to reflect forecasted power costs. PGE's and IP's mechanisms include a component under which a portion of the difference between actual and forecasted power costs is deferred for future recovery or refund. PGE's current power cost recovery framework includes both an annual update, under which rates change each January 1 to reflect updated net variable power costs, or NVPC, and a power cost adjustment mechanism, or PCAM, that is designed to capture a portion of the difference between the NVPC forecast established through the annual update, i.e., baseline NVPC, and the actual NVPC incurred by PGE for that year. The PCAM is subject to a deadband of $15 million below to $30 million above the ultimately established NVPC, a sharing ratio, and an earnings test. PGE absorbs 100% of the costs/benefits within a PUC-determined deadband, and amounts above or below the deadband are allocated 90% to customers and 10% to PGE shareholders. A surcharge or a refund would occur only if PGE's actual ROE is more than 100 basis points below or above PGE's last authorized ROE. PacifiCorp and IP have similar mechanisms.
South Carolina			Nonautomatic electric fuel and purchased gas adjustment clauses are in place for the state's utilities. Each electric utility is required to furnish the PSC an estimate of its fuel costs, including the cost of purchased power, for a prospective 12-month period. The PSC then determines the fuel-related costs to be included in base rates for that period, including adjustments for over or under recovery from the preceding 12-month period. Electric companies are required to account on a monthly basis for the difference between fuel costs recovered through base rates and actual fuel costs by booking the difference to unbilled revenue with a corresponding deferred debit or credit. Emissions allowance costs and the cost of certain materials used in reducing or treating emissions are reflected in the fuel clause.
South Dakota			Automatic fuel, purchased power, and gas cost adjustment clauses are permitted. Through these clauses, the utilities recover actual fuel, purchased power — energy portion only — and purchased gas expenses incurred; carrying costs accrue on unrecovered balances. The fuel clauses of Northern States Power-Minnesota, or NSP-MN, and Black Hills Power, or BHP, and NorthWestern Corp. contain certain incentive provisions.

State	Deadband	Risk Sharing	SNL Description of Adjustment Clause
Tennessee			Automatic purchased power and gas commodity recovery clauses are permitted. The state's gas utilities are allowed to reflect a portion of uncollectible expenses in these clauses. Kingsport Power, or KP, has a fuel and purchased power adjustment rider that reflects any changes in the wholesale costs of the company's power supplier, affiliate Appalachian Power, or APCO, as well as transmission expenses. KP has no generating capacity of its own, and purchases 100% of its power requirements from APCO. Chattanooga Gas, or CG, has a purchased gas adjustment rider in place.
Utah			The PSC may allow electric and gas utilities to implement balancing accounts to recover purchased power and fuel costs. In 2011, PacifiCorp implemented a pilot energy balancing account, or EBA, that was to remain in place through 2016 and contained incentive provisions. However, legislation was enacted on March 29, 2016, that removed the incentive provision of the mechanism and extended the EBA through 2019. Also, PacifiCorp operates under a renewable energy credit mechanism that contains certain incentive provisions.
Vermont	Yes. **Green Mountain Power** can recover or credit costs outside a $0.3 million band	Yes. Through its power supply cost adjustment mechanism, **Green Mountain Power** can annually pass through to ratepayers 90% of the energy costs (or benefits) varying by more than $0.3 million from the energy costs included in rates	Green Mountain Power Corp., or GMP, has a PCA in place that allows the company to recover from, or credit to, customers on an annual basis 90% of the energy costs that are more than $0.3 million higher or lower than the energy costs included in rates through a power supply cost adjustment mechanism. Vermont Gas Systems, or VGS, has a PGA mechanism in place that allows for the recovery of all gas-cost variations on a quarterly basis. The Vermont Supreme Court has prohibited the use of PCA and PGA mechanisms, finding them to be inconsistent with the customer notice requirements under state law. However, these mechanisms are permitted when adopted as part of an alternative regulation plan.
Virginia			Electric fuel adjustment clauses, or FACs provisions are permitted. The SCC's FAC procedure provides for electric rates to be reset annually based on projected usage and costs. The utilities maintain accounts for any over or underaccruals, and these balancing accounts are reconciled through the following year's fuel factor. Purchased power and capacity charges for "economy" purchases are included in the fuel factor calculation. Energy charges associated with reliability purchases may flow through the fuel factor, but capacity charges are recovered through base rates. Appalachian Power Co., or APCO, Virginia Electric and Power Co., or VEPCO, and Kentucky Utilities Co., all use an FAC.
Washington	Yes. **Avista, PSE**, and **PacifiCorp** employ deadbands of respectively ± $4 million, ±$17 million, and ±$4 million respectively	Yes. Under **Avista's** ERM, if costs are $4 million - $10 million lower than those included in base rates, 75% of the energy cost savings flow to customers. Costs between $4 million to $10 million higher are shared equally, while differences above $10 million are allocated 90% to customers and 10% to shareholders. **PSE** and **PacifiCorp** similarly pass costs to customers outside of a deadband based on a	Avista Corporation's Energy Recovery Mechanism, or ERM, allows the company to adjust rates to reflect changes in power supply-related costs, with 75% of any energy cost savings to flow to customers and 25% to the company when actual annual power costs are between $4 million and $10 million lower than those included in base rates. Equal sharing is to occur when actual power costs are between $4 million and $10 million greater than the amount included in base rates. Any differences in excess of $10 million are to be allocated 90% to customers and 10% to shareholders. The ERM contains an adjustment trigger under which a surcharge or rebate occurs when the deferred ERM balance reaches ±$30 million. Puget Sound Energy's, or PSE's, Power Cost Adjustment Mechanism, or PCAM, allows for variations in power costs to be apportioned, on a graduated scale, between the company and customers. Beginning in 2017, to the extent power costs are above/below the PCAM baseline amount, PSE is to absorb/retain the first $17 million above/below the baseline, and 10% of any amount that exceeds $40 million. For costs between $17 million and $40 million above the baseline, PSE is to absorb 50%. For costs between $17 million and $40 million below the baseline, PSE is to retain 35% of the benefits. A PCAM rate surcharge/credit is to be implemented when the deferred power cost balance reaches ±$20 million. Fixed production costs are no longer included in the PCAM. [...] In May 2015, the WUTC adopted a PCAM for PacifiCorp, following a settlement. The PCAM is a first for the company in Washington. The PCAM includes a $4 million dead band for net power cost variances, relative to a benchmark. For net power cost variances between $4 million and $10 million, the PCAM reflects asymmetrical sharing bands in which positive variances are to be allocated 50% to customers and 50% to PacifiCorp, and negative variances are to be allocated 75% to customers and 25% to PacifiCorp. Positive or negative net power cost variances in excess of $10 million are to be allocated 90% to customers and 10% to PacifiCorp.

State	Deadband	Risk Sharing	SNL Description of Adjustment Clause
West Virginia			Electric fuel and/or purchased power costs may be recovered through an ENEC proceeding. In addition to fuel costs, the ENEC reflects the energy portion of purchased power costs, the net benefit associated with affiliated and other wholesale sales, the demand portion of purchased power transactions, transmission costs and credits and any regional transmission organizationrelated costs. ENEC factors are set annually based on projected data for the prospective 12 months. Over- or under-recoveries based on actual data for the prior 12 month period are deferred for reconciliation as part of the next ENEC proceeding, with no carrying charges on the deferred balance. ENEC proceedings are typically completed within four months of filing.
Wisconsin	Yes, recovery for the five largest IOUs is subject to a ±2% deadband		Under the PSC's electric fuel rules, which apply to the state's five largest investor-owned utilities — Northern States Power Co. – WI, Wisconsin Power and Light Co., Madison Gas and Electric Co., Wisconsin Electric Power Co., and Wisconsin Public Service Corp. — each utility forecasts the monthly and annual fuel and purchased power costs on a prospective basis. If a company's actual fuel and purchased power costs are outside a monthly or cumulative monthly variance range around the forecasts and if the utility can demonstrate that these costs will likely be outside the annual range, the PSC may conduct a hearing to establish new rates. Currently, the annual variance range is plus or minus 2%. An electric utility is permitted to defer any fuel costs that are outside of its annual, symmetrical variance range for subsequent recovery or refund. However, the utility is prohibited from recovering deferrals if the company is found to be earning in excess of its authorized equity return.
Wyoming		Yes. **Cheyenne Light, Fuel & Power** can allocate steam production costs 85% to ratepayers and 15% to shareholders, and other eligible costs 95% to customers and 5% to shareholders. **PacifiCorp** similarly has cost-sharing in place, but allocates 70% to ratepayers and 30% to shareholders	Cheyenne Light, Fuel & Power, or CLF&P, operates under a power cost adjustment mechanism through which the company's power costs are classified into two categories. Category 1 costs include steam production costs, while category 2 costs include purchased power and capacity costs, transmission expenses, and certain other costs, and reflect any margins realized from off-system sales. Deviations in Category 1 costs from a base level are allocated 85% to ratepayers and 15% to shareholders. Deviations in Category 2 costs are allocated 95% to customers and 5% to shareholders. PacifiCorp operates under an energy cost adjustment mechanism, or ECAM, that is in place through 2017. Under the ECAM, incremental variations in net power costs that differ from the base level are allocated 70% to ratepayers and 30% to shareholders. In December 2015, the PSC approved the continuation of the current ECAM with certain modifications that allow for the inclusion of reagent chemical costs and start-up fuel costs. In addition, MDU Resources Group collects from/credits to ratepayers variations in fuel and purchased power costs that deviate from an established base level through a power supply cost adjustment mechanism.

Sources and Notes:

Descriptions of fuel adjustment clauses from SNL Energy Regulatory Research Associates (RRA) summaries. Deadband and Risk Sharing columns represent The Brattle Group interpretations of mechanisms according to these descriptions and research into utility filings.

REDACTED
Docket No. UE 374
Exhibit PAC/700
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Rick T. Link

February 2020

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ATTACHED EXHIBITS

Confidential Exhibit PAC/701—Nominal Henry Hub Natural Gas Price Forecasts

Exhibit PAC/702—Combined Projects System Optimizer and Planning and Risk PVRR(d) (Benefit)/Cost, February 2018

Exhibit PAC/703—Combined Projects Nominal Revenue Requirement PVRR(d) (Benefit)/Cost, February 2018

Confidential Exhibit PAC/704—Confidential Summary Planned Capital Investments

Confidential Exhibit PAC/705—Confidential Jim Bridger Plant Coal Costs

Confidential Exhibit PAC/706—Confidential Contributions to Mine Reclamation Trust

Confidential Exhibit PAC/707—Confidential Jim Bridger Coal Company Mine Capital Costs

Confidential Exhibit PAC/708—Confidential Natural Gas Price Assumptions used in the Evaluation of Jim Bridger Units 3 and 4

Confidential Exhibit PAC/709—Confidential System Optimizer Model Results for Gas Price Scenarios

Confidential Exhibit PAC/710—Relationship between Gas Prices and the PVRR

Confidential Exhibit PAC/711—Relationship between CO_2 Prices and the PVRR

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and position with PacifiCorp.

A. My name is Rick T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Vice President, Resource Planning and Acquisitions. I am testifying on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

Q. Please describe the responsibilities of your current position.

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

Q. Please describe your professional experience and education.

A. I joined PacifiCorp in December 2003 and assumed the responsibilities of my current position in September 2016. Over this time period, I held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities and developing financial models to evaluate resource investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I was responsible for delivering PacifiCorp's 2013, 2015, 2017, and 2019 IRPs; have been directly involved in several resource RFP processes; and performed economic analysis supporting a range of resource investment opportunities. Before joining PacifiCorp, I was an energy and environmental economics consultant with ICF Consulting (now

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

Q. Have you testified in previous regulatory proceedings?

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

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I describe how PacifiCorp's Energy Vision 2020 uses opportunities presented by the extension of the federal production tax credit (PTC) to make renewable energy and infrastructure investments that produce net benefits to customers. Energy Vision 2020 consists of two major components: (1) investments in new wind and transmission; and (2) wind repowering. I sponsor the economic analysis demonstrating that PacifiCorp's Energy Vision 2020 wind and transmission investments are reasonable and prudent. I also provide the economic analysis supporting the prudence of the last wind facility PacifiCorp is repowering, Foote Creek I. Through its Renewable Adjustment Clause (RAC) filing in docket UE 352, PacifiCorp previously received approval for cost recovery of nine of its repowered wind facilities,[1] and PacifiCorp's pending RAC filing in docket UE 369 seeks approval of two additional repowered wind facilities.[2]

In addition to Energy Vision 2020, PacifiCorp has acquired another wind resource, the Pryor Mountain Wind Project in Montana, which will achieve commercial operation in 2020. I present and explain the economic analysis that demonstrates that this investment is reasonable and prudent.

I also present economic analysis supporting major resource management decisions for PacifiCorp's coal generation facilities, including the conversion of Naughton Unit 3 to natural gas in 2020, the closure of Cholla Unit 4 in 2020, and the installation of selective catalytic reduction (SCR) emissions control systems at Jim Bridger Units 3 and 4 in 2015-2016.

Finally, I present PacifiCorp's sales and load forecast upon which this rate case filing is based.

Q. How have you organized your testimony?

A. I address PacifiCorp's new wind and transmission investments, collectively referred to as the "Combined Projects" in Section III of my testimony. Section IV of my testimony addresses repowering the Foote Creek I wind facility. I address PacifiCorp's new Pryor Mountain Wind Project in Section V of my testimony. Section VI presents PacifiCorp's resource decisions involving coal generation facilities, and Section VII presents PacifiCorp's sales and load forecast.

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[1] Docket No. UE 352 included the following wind repowering projects: Glenrock I, Goodnoe Hills, High Plains, Leaning Juniper, Marengo I, Marengo II, McFadden Ridge, Seven Mile Hill I, and Seven Mile Hill II.
[2] Docket No. UE 369 includes the following wind repowering projects: Glenrock III and Dunlap.

III. NEW WIND AND TRANSMISSION

Q. Please describe the new wind and transmission elements of Energy Vision 2020 included in this case.

A. By the end of 2020, PacifiCorp will add 1,150 megawatts (MW) of new wind resources in Wyoming. These resources are comprised of three facilities built by PacifiCorp, the 500 MW TB Flats I and II facilities and the 250 MW Ekola Flats project, and one facility that is a combined build-transfer agreement (BTA) and power purchase agreement (PPA), the 400 MW Cedar Springs facility[3] (collectively, the Energy Vision 2020 Wind Projects). These facilities were carefully selected to maximize value to customers in the 2017R RFP, which was monitored by independent evaluators (IE) from both Oregon and Utah.

Because PacifiCorp's current transmission system in eastern Wyoming is operating at capacity, PacifiCorp is also building a new, 140-mile Gateway West transmission sub-segment—the 500 kilovolt (kV) Aeolus-to-Bridger/Anticline transmission line, plus network upgrades—in Wyoming to enable this generation (collectively, Transmission Projects). As explained by PacifiCorp witness Mr. Richard A. Vail, the line allows PacifiCorp to interconnect up to 1,510 MW of new capacity, relieving existing transmission constraints in southeastern Wyoming. The new line increases transfer capability westbound by approximately 950 MW.

Q. Please summarize your testimony in Section III.

A. PacifiCorp's economic analysis shows that the investments in the Combined Projects are reasonable and prudent. The Energy Vision 2020 Wind Projects, which are

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[3] The Cedar Springs facility includes Cedar Springs I which is a 200 MW PPA and Cedar Springs II which is a 200 MW BTA.

enabled by the Transmission Projects, will generate PTCs for 10 years; produce zero-fuel-cost energy that will lower net power costs (NPC); generate renewable energy certificates (REC), which can be sold in the market to create additional revenues that would lower net customer costs or be used to comply with state renewable portfolio standard targets; and help decarbonize PacifiCorp's resource portfolio, which will mitigate long-term risk associated with potential future state and federal policies targeting carbon dioxide (CO_2) emissions reductions from the electric sector.

The Transmission Projects will relieve congestion on the current transmission system in eastern Wyoming, enable new wind resource interconnections, provide critical voltage support to the Wyoming transmission network, improve overall reliability of the transmission system, enhance PacifiCorp's ability to comply with mandated reliability and performance standards, and reduce line losses. Moreover, the proposed transmission-system investments create an opportunity for further increases to the transfer capability across the Aeolus-to-Bridger/Anticline line with the construction of additional segments of Energy Gateway.

The Combined Projects will produce customer benefits that significantly outweigh costs. The change in revenue requirement due to the Combined Projects was analyzed using two different IRP modeling tools across nine different scenarios, each with varying natural-gas and CO_2 price assumptions. For each of these scenarios, the present-value revenue requirement differential (PVRR(d)) was calculated from system revenue requirement forecasts through 2050 (through the 30-year life of the Energy Vision 2020 Wind Projects), reflecting nominal capital revenue requirement from the Combined Projects, and from system revenue requirement forecasts over a 20-year period, where capital revenue requirement is levelized.

The Combined Projects show net PVRR(d) benefits of $174 million in the medium case through 2050, and benefits of $338 million in the medium case through 2036. In the 18 scenarios studied (nine each for the 2050 and 2036 analyses), 16 of 18 cases show net customer benefits.

The customer benefits from the Combined Projects increase substantially with higher natural-gas price assumptions and higher CO_2 price assumptions. These benefits conservatively do not assign any value to the RECs that will be generated by the Energy Vision 2020 Wind Projects. For every dollar assigned to the incremental RECs that will be generated by the Wind Projects, present-value benefits would improve for all scenarios by an additional $38 million when calculated from the change in system revenue requirement through 2050. When calculated from the change in system revenue requirement over a 20-year period, each dollar assigned to the incremental RECs from the Energy Vision 2020 Wind Projects would increase PVRR(d) benefits by $31 million.

Sensitivity analysis shows that substantial benefits of the Combined Projects persist when paired with PacifiCorp's wind repowering project, addressed in dockets UE 352 and UE 369, and in Section IV of my testimony.

2017 Integrated Resource Plan

Q. Did PacifiCorp analyze new Wyoming wind resources and the Aeolus-to-Bridger/Anticline Line in its 2017 IRP?

A. Yes. The 2017 IRP preferred portfolio included 1,100 MW of new wind resources located in Wyoming. This wind capacity is enabled by the Aeolus-to-

Bridger/Anticline line, which is also included in the 2017 IRP preferred portfolio. The new wind and Aeolus-to-Bridger/Anticline line are assumed to be placed in service by the end of 2020 so that the new wind resources can qualify for the full value of PTCs.

Q. What led PacifiCorp to include 1,100 MW of new Wyoming wind resources and the Aeolus-to-Bridger Anticline Line in its 2017 IRP preferred portfolio?

A. All the resource portfolios produced during the initial stages of the portfolio-development phase of the 2017 IRP contained new Wyoming wind resources in 2021, which for modeling purposes was used as a proxy on-line date for PTC-eligible wind achieving commercial operation by the end of 2020. These results indicated that PTC-eligible wind resources located in wind-rich areas like Wyoming provide customer benefits.

During the initial stages of portfolio development for the 2017 IRP, the amount of Wyoming wind capacity that routinely appeared in 2021 was limited by transmission congestion on PacifiCorp's existing 230 kV transmission system. This congestion affects energy output from resources in eastern Wyoming where there is substantial potential to develop high-quality, low-cost wind resources. Wyoming resource selections at or near the limitation on Wyoming wind capacity caused by transmission constraints indicated clear potential for incremental customer benefits if incremental transmission is added to accommodate more PTC-eligible wind resources located in Wyoming.

To assess these potential incremental benefits, PacifiCorp reviewed components of its Energy Gateway transmission project to identify specific sub-segments that could access additional new Wyoming wind resources. In performing this review, PacifiCorp looked at the transmission interconnection queue and determined that sub-segment D.2 (the Aeolus-to-Bridger/Anticline Line) of the Energy Gateway transmission project could access a sizable volume of new wind projects being developed in the Aeolus area. PacifiCorp then developed an initial, high-level cost estimate for the Aeolus-to-Bridger/Anticline Line that was used for an initial Aeolus-to-Bridger/Anticline sensitivity assuming 650 MW of incremental transfer capability and 900 MW of new Wyoming wind resources.

Q. Why did PacifiCorp assume new wind resource capacity in excess of the assumed incremental transfer capability of the Aeolus-to-Bridger/Anticline Line in this initial sensitivity?

A. The Aeolus-to-Bridger/Anticline Line can enable new resource interconnections in excess of the transfer capability of the line. PacifiCorp's preliminary sensitivity in the 2017 IRP assumed the Aeolus-to-Bridger/Anticline Line would support at least 900 MW of new resource interconnections. The assumed level of new wind resources is higher than the assumed incremental transfer capability of the transmission line because wind resources do not generate at their full capability in all hours of the year. At times when wind resources in southeastern Wyoming are operating near full output, other resources in the area can be re-dispatched to accommodate PTC-producing wind generation.

Q. What were the results of this initial Aeolus-to-Bridger/Anticline sensitivity?

A. The initial sensitivity indicated that there could be economic benefits from aligning development of the Aeolus-to-Bridger/Anticline Line with new, PTC-eligible

Wyoming wind resources. Based on the promising results from this initial sensitivity, PacifiCorp reviewed its initial, high-level assumptions to determine how refined inputs would affect potential benefits from the incremental new Wyoming wind resources and the Aeolus-to-Bridger/Anticline Line.

PacifiCorp completed power flow and dynamic-stability studies to refine its Aeolus-to-Bridger/Anticline Line assumptions. These studies supported increasing the assumed incremental transfer capability of the new transmission line from 650 MW to 750 MW and suggested that it could enable up to 1,270 MW of new resource interconnections. PacifiCorp also refined its initial, high-level cost assumptions, reducing the estimated capital cost of the project by over $100 million.

In addition, PacifiCorp reviewed its new wind resource cost-and-performance assumptions, initially developed to represent proxy Wyoming wind resources, to focus on specific projects that could be developed in the Aeolus area. Based on this review, PacifiCorp determined that the estimated capital cost for new wind resources could be lowered by 10.7 percent from its initial proxy cost assumptions and that its wind capacity factor assumptions should be reduced from 43 percent to 41.2 percent.

PacifiCorp also reviewed whether additional benefits from the wind enabled by the Aeolus-to-Bridger/Anticline Line could be quantified. PacifiCorp identified and quantified three additional value streams associated with its participation in the Energy Imbalance Market (EIM), improved transmission reliability, and reduced transmission line losses. The results from this additional review and analysis were applied in the final 2017 IRP resource-portfolio screening process, where PacifiCorp conducted additional studies that considered analysis performed in earlier resource-portfolio screening stages.

Q. What type of analysis did PacifiCorp consider from earlier resource-portfolio screening stages?

A. In earlier stages of its resource-portfolio screening process, PacifiCorp developed a wind repowering sensitivity, where certain existing wind resources qualify for an additional 10 years of PTCs after they are upgraded with modern equipment. The wind repowering project, discussed in dockets UE 352 and UE 369 and in Section IV of my testimony, showed significant net customer benefits across a range of assumptions related to forward market prices and federal CO_2 policy based on the Clean Power Plan. Considering the significant customer benefits associated with the wind repowering project, PacifiCorp combined its refined assumptions for incremental new Wyoming wind and the Aeolus-to-Bridger/Anticline Line in a study that included wind repowering.

Q. What were the results of PacifiCorp's final 2017 IRP resource-portfolio screening process that incorporated refined and expanded input assumptions for incremental new Wyoming wind resources and the Aeolus-to-Bridger/Anticline Line?

A. Studies developed for the final 2017 IRP resource-portfolio screening process showed significant net customer benefits relative to other resource-portfolio alternatives. Based on these results, the Aeolus-to-Bridger/Anticline Line and the 1,100 MW of new Wyoming wind resources, both assumed to be placed in service by the end of 2020, were included in the 2017 IRP preferred portfolio.

Q. Did PacifiCorp include an action item for new Wyoming wind resources in its 2017 IRP action plan?

A. Yes. The 2017 IRP action plan, which lists the specific steps PacifiCorp will take over the next two to four years to deliver resources in the preferred portfolio, includes the following action item associated with the new Wyoming wind resources:

> PacifiCorp will issue a wind resource RFP for at least 1,100 MW of Wyoming wind resources that will qualify for federal wind production tax credits and achieve commercial operation by December 31, 2020.
>
> - April 2017, notify the Utah Commission of intent to issue the Wyoming wind resource RFP.
> - May-June, 2017, file a draft Wyoming wind RFP with the Utah Commission and the Washington Commission.
> - May-June, 2017, file to open a Wyoming wind RFP docket with the Commission and initiate the IE RFP.
> - June-July, 2017, file a draft Wyoming wind RFP with the Commission and file a Public Convenience and Necessity (CPCN) application with the Wyoming Commission.
> - By August 2017, obtain approval of the Wyoming wind resource RFP from the Commission, the Utah Commission and the Washington Commission.
> - By August 2017, issue the Wyoming wind RFP to the market.
> - By October 2017, Wyoming wind RFP bids are due.
> - November-December, 2017, complete initial shortlist bid evaluation.
> - By January 2018, complete final shortlist bid evaluation, seek acknowledgment of the final shortlist from the Commission, and seek approval of winning bids from the Utah Commission.
> - By March 2018, receive CPCN approval from the Wyoming Commission.
> - Complete construction of new wind projects by December 31, 2020.

Q. Did PacifiCorp also include an action item for the Aeolus-to-Bridger/Anticline Line in its 2017 IRP action plan?

A. Yes. The 2017 IRP action plan includes the following action item associated with the Aeolus-to-Bridger/Anticline line:

> By December 31, 2020, PacifiCorp will build the 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This includes pursuing regulatory review and approval as necessary.
>
> - June-July 2017, file a CPCN application with the Wyoming Commission.
> - By March 2018, receive conditional CPCN approval from the Wyoming Commission pending acquisition of rights of way.
> - By December 2018, obtain Wyoming Industrial Siting permit and issue engineer, procure, and construct (EPC) limited notice to proceed.
> - Complete construction of the transmission line by December 31, 2020.

Q. Did the Commission acknowledge the Combined Projects in PacifiCorp's 2017 IRP action plan?

A. Yes. The Commission acknowledged the action items containing the Combined Projects, with conditions, at a Special Public Meeting in December 2017, as memorialized in Order 18-138 in docket LC 67.[4]

Q. What conditions did the Commission include with its acknowledgment of these action items?

A. The Commission directed PacifiCorp to provide an updated economic analysis with its request for acknowledgment of the final shortlist for the 2017R RFP, and to update

[4] *In the Matter of PacifiCorp, dba Pacific Power*, Docket LC 67, Order No. 18-138, at 8 (Apr. 27, 2018).

its analysis of these projects as part of its 2017 IRP Update, including any changes resulting from the RFP or changes to critical assumptions.[5] In addition, the Commission requested quarterly updates as the wind projects selected in the RFP process and the transmission project proceed, up through the date the projects go into service.[6]

Q. Has PacifiCorp fulfilled these conditions?

A. Yes. As part of the 2017R RFP process, PacifiCorp conducted economic analysis using the same models as in the 2017 IRP to evaluate bids and develop an RFP shortlist. PacifiCorp reported the results of this updated analysis in its request for acknowledgment of the RFP shortlist in docket UM 1845 in February 2018,[7] and incorporated these results into its 2017 IRP Update filed with the Commission in docket LC 67 in May 2018.[8] PacifiCorp has also since provided six quarterly updates on the status of project permitting and construction to date, with the most recent update filed in October 2019.[9]

Q. Did the Commission provide any other qualifications on acknowledgment of the 2017 IRP action items for the Combined Projects?

A. Yes. In its acknowledgment order, the Commission reserved the right to impose conditions ensuring the benefits of the Combined Projects are not less than IRP projections.[10] Importantly, however, the Commission made clear that it was not

[5] Order No. 18-138 at 8.
[6] *Id*.
[7] *In the Matter of PacifiCorp, dba Pacific Power, 2017R Request for Proposals*, Docket No. UM 1845, PacifiCorp's Corrected Request for Acknowledgment of Final Shortlist of Bidders in 2017R Request for Proposals, at 10-33 (Feb. 23, 2018).
[8] Docket No. LC 67, PacifiCorp's 2017 Integrated Resource Plan Update, at 102-105 (May 1, 2018).
[9] Docket No. LC 67, PacifiCorp's Compliance Filing - New Wind and Transmission Projects Quarterly Update, at 4, 6-7 (Oct. 31, 2019).
[10] Order No. 18-138 at 8, 9.

setting rates or pre-judging ratemaking issues.[11] The Commission issued this IRP order when the projects were still early in development. More than two years later, PacifiCorp is well into implementing the Combined Projects, and during this time it has carefully managed the many different facets of project development risks. As evidenced by the quarterly updates filed in docket LC 67, and as discussed in the testimony of PacifiCorp witness Mr. Chad A. Teply, PacifiCorp is positioned to complete the Combined Projects on time and on budget.

Q. Did PacifiCorp address the Combined Projects in its 2019 IRP?

A. All resource portfolios developed for the 2019 IRP include the Combined Projects, which are under construction. New resource acquisitions were evaluated assuming the Combined Projects will be placed in service by the end of 2020.

2017R RFP

Q. When did PacifiCorp issue the 2017R RFP called for in the 2017 IRP?

A. At the time PacifiCorp issued the 2017R RFP, PacifiCorp was subject to resource procurement requirements in Oregon under the Competitive Bidding Guidelines established by Order 06-446 in docket UM 1182,[12] and in Utah under Utah Code Ann. § 54-17-201 *et. seq.* PacifiCorp issued the 2017R RFP on September 27, 2017, after

[11] *Id.* at 3 ("Our decision to acknowledge or not acknowledge an action item does not constitute ratemaking. The question of whether a specific investment made by a utility in its planning process was prudent will be fairly examined in the subsequent ratemaking."); *see also id.* at 9 (explaining that the Commission "intend[s] to protect customers going forward, while still giving the Company the flexibility to try to capture the significant economic benefits that the Company's planning assumptions show PTC-enabled resources would deliver to customers").

[12] *In the Matter of Public Util. Comm. of Oregon, Investigation Regarding Competitive Bidding*, Docket No. UM 1182, Order No. 06-446, at 15, Appendix A (Aug. 10, 2006). *See also* Docket No. UM 1182, Order No. 14-149, at 18, Appendix A (Apr. 30, 2014) (revising Guidelines). The Commission subsequently adopted competitive bidding rules.

it was approved by the Utah Commission on September 22, 2017,[13] and by this Commission on September 27, 2017.[14]

Q. Please elaborate on the Commission's RFP approval order in docket UM 1845.

A. Under Oregon's Competitive Bidding Guidelines, the Commission focuses on three factors in reviewing a final draft RFP: "(1) the alignment of the utility's RFP with its acknowledged IRP; (2) whether the RFP satisfies the Commission's competitive bidding guidelines; and (3) the overall fairness of the utility's proposed bidding process."[15] As the Commission has explained, "[t]he ultimate goal of the RFP process is the same as the IRP process—to minimize long-term costs and risks[,]" but whereas the IRP process focuses on resource need, "[t]he RFP process focuses on how the utility executes the procurement process[.] . . ."[16]

The Commission initially approved the 2017R RFP at a Special Public Meeting on August 29, 2017, subject to the condition that PacifiCorp subsequently receive acknowledgment of the Combined Projects in its 2017 IRP docket.[17] In so doing, the Commission explained that "unique time constraints" imposed by expiring PTCs justified approving the RFP before IRP acknowledgment.[18] On September 27, 2017, the Commission issued an amended order approving the 2017R RFP as modified to conform with the Utah Commission's approval decision.[19] Among other

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[13] *Application of Rocky Mountain Power for Approval of Solicitation Process for Wind Resources*, Docket No. 17-035-23, Order Approving RFP with Suggested Modification, at 11-12 (Sept. 22, 2017).
[14] Docket No. UM 1845, Order No. 17-345, at 2 (Sept. 14, 2017), amended in Order No. 17-367 (Sept. 27, 2017).
[15] Order No. 14-149, Appendix A, at 2 (Guideline #7); Order No. 17-345 at 2 (summarizing same).
[16] Docket No. UM 1845, Order No. 18-178, at 10 (May 23, 2018).
[17] Order No. 17-345 at 2. The Commission also conditioned its approval subject to several modifications to RFP terms requested by the IE and other parties. *See id.* at 3-4; Docket No. UM 1845, Order No. 17-367 (Sept. 27, 2017).
[18] Order No. 17-345 at 2.
[19] Order No. 17-367.

changes, the modified 2017R RFP allowed bids from non-Wyoming wind projects.

As with the 2017 IRP acknowledgment order, the Commission emphasized it was not setting rates or pre-judging ratemaking issues.[20] Rather, approval of an RFP, the Commission explained, is "[s]imply a determination on the three criteria set out in the guideline . . . . The approval is simply that: the RFP meets these criteria, does not meet the criteria, or would meet the criteria with certain conditions and modifications."[21]

Q. In response to the Utah Commission's approval order, did PacifiCorp decide to issue a solar RFP to run concurrently with the 2017R RFP?

A. Yes. In its order approving the 2017R RFP, the Utah Commission suggested, but did not require, a modification to expand the 2017R RFP to solicit solar resource bids. To maintain the 2017R RFP schedule while addressing the Utah Commission's suggestion, PacifiCorp issued a separate solicitation process for solar resources, the 2017S RFP, on November 15, 2017. The 2017S RFP allowed the Company to: (1) evaluate how solar resource bids might impact the economic analysis of bids selected to the final shortlist in the 2017R RFP without delaying the schedule for the 2017R RFP; and (2) explore whether new solar resource opportunities might provide all-in economic benefits for customers.

Q. Please describe the key milestones in the 2017R RFP.

A. First, PacifiCorp received initial bids in October 2017. The 2017R RFP was well

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[20] *Id.* at 2 ("[A] decision to approve an RFP does not constitute any determination on the prudence of the resource acquisition. Any ratemaking determinations would occur at a later time."). *See also id.* at 3 ("If the Company proceeds to rate recovery, we will continue to scrutinize the resource selection, as we recognize that a rushed process makes it harder to comprehensively review the matter before us, and will ultimately be taken into consideration in future proceedings.").
[21] *Id.* at 2.

received by the market, with 5,219 MW of new wind resource capacity bid into the 2017R RFP (4,624 MW of Wyoming wind and 595 MW of non-Wyoming wind).

Second, PacifiCorp evaluated bids and selected the initial shortlist in November 2017. The establishment of the final shortlist was delayed by the need for refreshed bids to account for the enactment of the Tax Cuts and Jobs Act (TCJA) in December 2017.

Third, PacifiCorp announced its final shortlist in January 2018. The final shortlist consisted of four new wind projects located in Wyoming with a total capacity of 1,170 MW, including three of the Company's benchmark facilities (TB Flats I and II, now combined as a single 500 MW project, and the 109 MW McFadden Ridge II project), and two new facilities: Uinta, a BTA totaling 161 MW, and Cedar Springs, one-half BTA and one-half PPA, for a total of 400 MW.

Fourth, PacifiCorp updated the final shortlist in February 2018 after completing its interconnection-restudy process. PacifiCorp initially developed the final shortlist based on economic analysis of the bids without consideration of interconnection queue position, specifically at the request of IEs and comments in the RFP process.[22] Based on the results of the interconnection restudies, PacifiCorp removed the McFadden Ridge II benchmark because it could not be interconnected with just the addition of the Aeolus-to-Bridger/Anticline transmission line. The updated final shortlist added the Ekola Flats benchmark bid and increased the total capacity in the updated final shortlist to 1,311 MW. In its restudy process, PacifiCorp

[22] Docket No. UM 1845, PacifiCorp's Reply Comments, at 14-15 (Mar. 29, 2018) ("RFP Reply Comments"); Docket No. UM 1845, PacifiCorp's Comments on Staff's Report, at 4 (Apr. 19, 2018) ("RFP Comments on Staff Report").

confirmed the Aeolus-to-Bridger/Anticline Line will enable interconnection of up to 1,510 MW of new wind capacity within the constrained area of PacifiCorp's transmission.

Q. Please summarize the role of the IEs who monitored the 2017R RFP.

A. The 2017R RFP was overseen by two IEs—one appointed by the Commission and retained by PacifiCorp, and one appointed and retained by the Utah Commission. In accordance with the applicable statutes, rules, and policies in Oregon and Utah, the IE is an independent expert appointed and managed by the respective state commissions (not PacifiCorp) to ensure an RFP process is conducted in a fair and unbiased manner and the final shortlist projects are reasonable and consistent with the modeling results used to evaluate bids.[23]

In the 2017R RFP, both IEs were involved from the beginning—providing feedback and recommendations regarding the design and content of the 2017R RFP and actively participating in every stage of the RFP. For its part, PacifiCorp ensured the IEs had complete and unrestricted access to all information related to the 2017R RFP and kept both IEs informed of developments as they occurred.

Q. Did the IEs provide an assessment of PacifiCorp's benchmark resources bid into the 2017R RFP (*i.e.*, TB Flats I and II, Ekola Flats, and McFadden Ridge II)?

A. Yes. Because the 2017R RFP included benchmark resources, both IEs provided detailed assessments of the benchmark bids to ensure they were reasonable and would not bias the solicitation in favor of utility-owned resources. The benchmark review process occurred before any other bids were received to provide additional assurance

[23] OAR 860-089-0200, 860-089-0450; Order No. 14-149, Appendix A, at 2 (Guideline #5); Utah Code § 54-17-203; Utah Admin. Code R746-420-1 - R746-420-6.

that the benchmarks were not provided an unfair advantage.

Q. Did the IEs confirm the reasonableness of the benchmark bids?

A. Yes. The Oregon IE conducted a thorough assessment of the benchmarks, noting that when "assessing a utility's own bids in response to the RFP, our greatest concern is that the utility will incorporate cost estimates that have been aggressively estimated and do not characterize the costs of the project accurately."[24] To make its assessment, the Oregon IE "looked at a detailed breakdown of each of the benchmarks costs to determine if any items have been improperly omitted from the cost calculation, and at overall capital cost levels by comparing them to publicly-available data on recent wind generation capital costs."[25] This "comparison provided a measure of the overall reasonableness of the Benchmark capital costs and capacity factors."[26] The Oregon IE ultimately found that the benchmarks were acceptable based on three items:

- First, the benchmarks were not deliberately under-priced through omission of any capital cost components.
- Second, the benchmark capital and operating costs appeared reasonable when compared with public data on U.S. wind projects.
- Third, the capacity factors of the benchmarks were reasonable when compared with public data and were supported by credible third-party analysis.[27]

The Utah IE similarly concluded that: (1) PacifiCorp provided detailed information related to the benchmarks that exceeded industry standards; (2) cost estimates were reasonable; and (3) the review, assessment, and scoring of the benchmark resources was conducted in a fair and equitable manner with no outward

[24] Docket No. UM 1845, Revised Independent Evaluator's Final Report on PacifiCorp's 2017R Request for Proposals, at 10 (Feb. 20, 2018) ("Oregon IE Report").
[25] *Id.*
[26] *Id.*
[27] *Id. at 10-11.*

perception of bias.[28]

Q. Please describe Oregon's RFP shortlist acknowledgment process.

A. Under the Competitive Bidding Guidelines, in addition to seeking Commission approval of the RFP prior to commencement of bidding, a utility must subsequently request acknowledgment of its selection of the final shortlist of RFP resources coming out of that bidding process.[29] Acknowledgment "means only that the [shortlist] seems reasonable to the Commission at the time the acknowledgment is given."[30] In a subsequent cost recovery proceeding, acknowledgment of an RFP shortlist has the same effect as IRP acknowledgment.[31] In other words, the decision whether to acknowledge a utility's shortlist "does not constitute ratemaking[,]" and "[t]he question of whether a specific investment made by a utility in its planning process is prudent will be fairly examined in the subsequent rate proceeding."[32]

Q. Did the Oregon IE recommend acknowledgment of the 2017R RFP Shortlist?

A. Yes. The Oregon IE recommended the Commission approve PacifiCorp's final shortlist based on the following conclusions:

- The selected bids represent the top offers that are viable under current transmission planning assumptions and provide the greatest benefits to ratepayers.
- The selected bids represent the best viable options from a competitive perspective, based on the 59 bid options presented.

[28] Docket No. 17-035-23, Redacted Final Report of the Independent Evaluator Merrimack Energy Group, Inc., at 44-45 (Feb. 27, 2018) ("Utah IE Report").
[29] Order No. 14-149, Appendix A at 5 (Guideline #13).
[30] *In The Matter Of The Investigation Into Least-cost Planning In Oregon*, Docket No. UM 180, Order No. 89-507, 102 PUR4th 301 (Apr. 20, 1989); Order No. 14-149, Appendix A, at 5 (explaining that with respect to an RFP shortlist, "[a]cknowledgment has the same meaning as assigned to that term in Commission Order No. 89-507.").
[31] Order No. 14-149, Appendix A at 5 (Guideline #13).
[32] Order No. 18-138 at 3 (discussing the IRP acknowledgement process).

- The IE's analysis confirmed that the selected bids were reasonably priced and, while not the lowest-cost offers, were the lowest-cost offers that were viable under current transmission planning assumptions. The IE's analysis included its own cost models for each bid option and a review of PacifiCorp's models.
- The IE took special care to confirm the selection of PacifiCorp's benchmark resources. The IE confirmed the accuracy of the benchmark costs and scoring. The IE noted that the benchmark bids were disciplined by the fact that a third-party bidder submitted a competing offer for a BTA for benchmark projects.
- The IE confirmed that the 2017R RFP aligns with the acknowledged 2017 IRP and that the shortlist was developed using IRP assumptions and models.[33]

Q. How did the Commission proceed with PacifiCorp's RFP shortlist?

A. In May 2018, the Commission issued a decision declining to acknowledge PacifiCorp's shortlist, based in large part on concerns about how transmission interconnection constraints imposed by the Federal Energy Regulatory Commission (FERC) narrowed the shortlist of eligible projects.[34]

Q. Please describe the interconnection constraints.

A. Under PacifiCorp's open access transmission tariff (OATT) and the policies and precedent established by FERC, PacifiCorp transmission must process and study projects for interconnection in serial order, based on the date the generator requests interconnection.[35] Federal interconnection requirements therefore limited the number of projects bidding into the RFP process that would be eligible to interconnect and achieve commercial operation prior to the impending PTC deadline.[36]

Q. How did the interconnection constraint affect the RFP shortlist?

A. PacifiCorp's interconnection restudy process resulted in displacing one of the

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[33] Oregon IE Report at 2-3; Order No. 18-178 at 4.
[34] Order No. 18-178 at 9.
[35] PacifiCorp OATT Section 38.8, available at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20191219_OATTMASTER.pdf.
[36] RFP Reply Comments at 9-11.

benchmark projects (McFadden Ridge II) with another benchmark project (Ekola Flats).[37] The interconnection restudy process did not replace any third-party projects with benchmark projects.

Q. Did the IEs address the interconnection queue issue?

A. Yes. Both IEs agreed with PacifiCorp's assessment that projects with interconnection queue numbers greater than Q0712 were non-viable. Although both IEs expressed some frustration about the limitations imposed by these issues, both concluded that the process was nonetheless fair, transparent, and unbiased.

The Oregon IE explained that PacifiCorp's "transmission arm, which assesses interconnection costs, must, by law, assume that each queue project is interconnected in order received so each project assumes that all projects ahead of it in the queue are interconnected."[38] Thus, "[a]s more projects in the Wyoming area are interconnected it puts more strain on the transmission system until eventually major upgrades such as the Gateway West and South projects are needed."[39] In this case, the major upgrades were required for all projects with queue numbers greater than Q0712. The Oregon IE concluded that it "understand[s] and appreciate[s] PacifiCorp's position and do[es] not disagree with their transmission department's findings (beyond noting the obvious fact that many projects will likely drop out of the queue and that actual interconnection costs will differ from projected)."[40] According to the IE, "[t]o go forward with projects that cannot meet the proposed online date without major accelerated transmission investment would not seem to be the wisest course of

[37] *Id.* at 13-14; RFP Comments on Staff Report at 3-4.
[38] Oregon IE Report at 32.
[39] *Id.*
[40] *Id.* at 35.

action."[41]

The Utah IE found that the final shortlist of projects "was a reasonable selection based on the constraints identified."[42]

Q. Order 18-178 on the final shortlist was issued less than a month after Order 18-138 acknowledging the 2017 IRP. Did the Commission provide any context for the interplay between these two orders?

A. Yes. The Commission was careful to qualify that its decision with respect to the RFP shortlist "does not diminish [the] earlier acknowledgment of PacifiCorp's proposal to acquire renewable resources[]" in the IRP docket.[43]

The Commission emphasized that it did not conclude PacifiCorp "acted inappropriately" in conducting the RFP or in managing its transmission queue.[44] Rather, the Commission recognized the time constraints imposed by expiring PTCs led to the unusual circumstances at issue in the RFP docket:

> We believe that accommodating PacifiCorp's request for an out-of-order RFP process, in which we were asked to approve PacifiCorp's RFP well before we concluded our review of the IRP, combined with an expedited schedule, is the primary factor that resulted in a RFP design, process and, ultimately, shortlist that did not meet our expectations . . . .[45]

Notwithstanding concerns about the impact transmission requirements had on the shortlisted projects, the Commission clarified that going forward, it is "committed to give fair regulatory treatment to resource decisions that PacifiCorp ultimately makes."[46]

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[41] *Id.*
[42] Utah IE Report at 84.
[43] Order No. 18-178 at 9.
[44] *Id.* at 13.
[45] *Id.*
[46] *Id.* at 14.

Q. Did the Utah IE provide any overall conclusions related to the 2017R RFP?

A. Yes. The Utah IE supported the final shortlist projects based on the following conclusions:

- The 2017R RFP was fair, reasonable, and generally in the public interest.[47]
- The bid evaluation and selection processes were designed to lead to the acquisition of wind-generated electricity at the lowest reasonable cost based on the detailed state-of-the-art portfolio evaluation methodology used, the steps taken to achieve comparability between utility cost-of-service resources and third-party firm priced bids, the flexibility afforded bidders via a range of eligible resource alternatives, and the attempt to allow for equal terms for PPA and BTA resources.[48]
- PacifiCorp's modeling demonstrates that the Combined Projects "should result in significant savings for customers."[49] Further, because PTCs will flow through to customers in the first 10 years, the "near-term benefits to customers should be significant."[50]

Energy Vision 2020 CPCN/Pre-Approval Filings

Q. Did PacifiCorp seek a CPCN for the Combined Projects from the Wyoming Commission?

A. Yes. Because the Combined Projects are being constructed in Wyoming, PacifiCorp filed an application for a CPCN at the Wyoming Commission in June 2017.

Q. Did the Wyoming Commission approve PacifiCorp's CPCN application?

A. Yes. In April 2018, the Wyoming Commission approved the CPCN based on a stipulation among several parties. In the stipulation, PacifiCorp agreed to remove the 161 MW Uinta facility from the final shortlist. This reduced the total capacity of the Wind Projects from 1,311 MW to 1,150 MW. PacifiCorp updated its February 2018 economic analysis to reflect this change.

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[47] Utah IE Report at 70.
[48] *Id.* at 71.
[49] *Id.*
[50] *Id.* at 83.

Q. Did PacifiCorp request and receive approval for the Combined Projects in other states?

A. Yes. PacifiCorp filed for a CPCN in Idaho. In Utah, PacifiCorp requested approval under Utah Code Ann. § 54-17-302 for the Company's "significant energy resource decision" to acquire the Wind Projects; it also requested approval under Utah Code Ann. § 54-17-402 for its "resource decision" to construct the Transmission Projects. The Company updated both applications to remove the Uinta facility based on the stipulation in Wyoming. The Utah and Idaho Commissions granted the applications in June and July 2018, respectively.

Modeling Methodology

Q. Please describe the chronology of PacifiCorp's analyses of the Combined Projects.

A. PacifiCorp's initial economic analysis of the Combined Projects was in the 2017 IRP. The Company updated this analysis in June 2017 when it filed for CPCNs and pre-approval in Wyoming, Utah, and Idaho. After the initial final shortlist was selected, PacifiCorp updated its analysis in January 2018 to reflect the winning bids, which at the time included McFadden Ridge II. Following the completion of the interconnection restudies, in February 2018, PacifiCorp updated its economic analysis to replace McFadden Ridge II with Ekola Flats. After the stipulation removing Uinta from the Combined Projects, PacifiCorp adjusted its February 2018 analysis to reflect this change.

Q. What economic analysis did PacifiCorp rely upon in deciding to move forward with its investment in the Combined Projects?

A. PacifiCorp relied upon its economic analysis from February 2018, adjusted to remove the Uinta facility, to make its decision to move forward with the Combined Projects.

System Modeling Methodology

Q. Please summarize the methodology PacifiCorp used in its system analysis of the Combined Projects.

A. PacifiCorp relied upon the same modeling tools used to develop resource portfolios in its 2017 IRP to refine its analysis of the Combined Projects. These IRP modeling tools, described further below, calculate system present value revenue-requirement (PVRR) by identifying least-cost resource portfolios and dispatching system resources over a 20-year forecast period (2017–2036). Net customer benefits are calculated as the PVRR(d) between two simulations of PacifiCorp's system. One simulation includes the Combined Projects, and the other simulation excludes the Combined Projects. Customers are expected to realize net benefits when the system PVRR with the Combined Projects is lower than the system PVRR without the Combined Projects. Conversely, customers would experience increased costs if the system PVRR with the Combined Projects were higher than the system PVRR without the Combined Projects.

Q. What modeling tools did PacifiCorp use to perform its economic analysis of the Combined Projects?

A. PacifiCorp used the System Optimizer (SO) model and the Planning and Risk model (PaR) to develop resource portfolios and to forecast dispatch of system resources in simulations with and without the Combined Projects.

Q. Please describe the SO and PaR models.

A. The SO model is used to develop resource portfolios with sufficient capacity to achieve a target planning-reserve margin. The SO model selects a portfolio of resources from a broad range of resource alternatives by minimizing the system PVRR. In selecting the least-cost resource portfolio for a given set of input assumptions, the SO model performs time-of-day, least-cost dispatch for existing resources and prospective new resource alternatives, while considering the cost-and-performance characteristics of existing contracts and prospective demand-side management (DSM) resources—all within or connected to PacifiCorp's system. The system PVRR from the SO model reflects the cost of existing contracts, wholesale-market purchases and sales, the cost of new and existing generating resources (fuel, fixed and variable operations and maintenance, and emissions, as applicable), the cost of new DSM resources, and levelized revenue requirement of capital additions for existing coal resources and potential new generating resources.

PaR is used to develop a chronological unit commitment and dispatch forecast of the resource portfolio generated by the SO model, accounting for operating reserves, volatility and uncertainty in key system variables. PaR captures volatility and uncertainty in its unit commitment and dispatch forecast by using Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural-gas prices, hydro generation, and thermal unit outages. PaR uses the same common input assumptions that are used in the SO model, with resource-portfolio data provided by the SO model results. The PVRR from PaR reflects a distribution of system variable costs, including variable costs associated with existing contracts, wholesale-market purchases and sales, fuel costs, variable operations and maintenance (O&M) costs, emissions costs, as applicable, and costs associated with energy or reserve deficiencies. Fixed costs that do not change with system dispatch, including the cost of DSM resources, fixed O&M costs, and the levelized revenue requirement of capital additions for existing coal resources and potential new generating resources, are based on the fixed costs from the SO model, which are combined with the distribution of PaR variable costs to establish a distribution of system PVRR for each simulation.

Q. How has PacifiCorp historically used the SO and PaR models?

A. PacifiCorp uses the SO model and PaR to produce and evaluate resource portfolios in its IRP and to evaluate bids in its RFPs. PacifiCorp also uses these models to analyze resource-acquisition opportunities, resource retirements, resource capital investments, and system transmission projects.

Q. Are the SO and PaR models the appropriate tools for analyzing the Combined Projects opportunity?

A. Yes. The SO model and PaR are the appropriate modeling tools when evaluating significant capital investments that influence PacifiCorp's resource mix and affect least-cost dispatch of system resources. The SO model simultaneously and endogenously evaluates capacity and energy trade-offs associated with resource capital projects and is needed to understand how the type, timing, and location of future resources might be affected by the Combined Projects. PaR provides additional granularity on how the Combined Projects are projected to affect system operations, recognizing that key system conditions are volatile and uncertain. Together, the SO model and PaR are best suited to perform a net-benefit analysis for the Combined Projects opportunity that is consistent with long-standing risk-adjusted, least-cost planning principles applied in PacifiCorp's IRP.

Q. How did PacifiCorp use PaR to assess stochastic system cost risk associated with the Combined Projects?

A. Just as it evaluates resource-portfolio alternatives in the IRP, PacifiCorp uses the stochastic-mean PVRR and risk-adjusted PVRR, calculated from PaR study results, to assess the stochastic system-cost risk of the Combined Projects. With Monte Carlo sampling of stochastic variables, PaR produces a distribution of system variable costs. The stochastic-mean PVRR is the average of net variable operating costs from the distribution of system variable costs, combined with system fixed costs from the SO model. PacifiCorp uses a risk-adjusted PVRR to evaluate stochastic system cost risk. The risk-adjusted PVRR incorporates the expected value of low-probability, high-cost outcomes. The risk-adjusted PVRR is calculated by adding five percent of system variable costs, from the 95th percentile of the distribution of system variable costs, to the stochastic-mean PVRR.

When applied to the Combined Projects analysis, the stochastic-mean PVRR represents the expected level of system costs from cases with and without the Combined Projects. The risk-adjusted PVRR is used to assess whether the Combined Projects cause a disproportionate increase to system variable costs under low-probability, high-cost system conditions.

Q. Please describe how the effective combined federal and state income tax rate assumption is applied in the SO model and the PaR in the economic analysis.

A. The effective combined federal and state income tax rate affects PacifiCorp's post-tax weighted average cost of capital, which is used as the discount rate in the SO model and PaR. Accounting for recent changes in tax law, the discount rate used in the economic analysis is 6.91 percent.

The income tax rate also affects the capital revenue requirement for all new resource options available for selection in the SO model. Capital revenue requirement is levelized in the SO and PaR models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. This is achieved through annual capital recovery factors, which are expressed as a percentage of the initial capital investment for any given resource alternative in any given year. Capital recovery factors, which are based on the revenue requirement for specific types of assets, are differentiated by each asset's assumed life, book-depreciation rates, and tax-depreciation rates. Because capital revenue requirement accounts for the impact of income taxes on rate-based assets, the capital recovery factors applied to new resource costs in the SO model were reflected for each system simulation.

Finally, the income tax rate affects the tax gross-up of all PTC-eligible resources. At the time, federal PTCs were $24/megawatt-hour (MWh), which equates to a $31.82/MWh reduction in revenue requirement assuming an effective combined federal and state income tax rate of 24.587 percent. The impact of the income tax rate assumptions were applied to all PTC-eligible resource alternatives available in the SO model.

Q. What assumptions did PacifiCorp use in its economic analysis of the Combined Projects in February 2018?

A. The models reflect: (1) cost-and-performance assumptions for the Wind Projects consistent with the winning bids selected to the 2017R RFP final shortlist; (2) the latest load-forecast projections; (3) the latest price-policy scenario assumptions; and (4) changes in federal tax rate for corporations under the TCJA.

Q. Please describe the cost-and-performance estimates for the Energy Vision 2020 Wind Projects in the February 2018 economic analysis.

A. The February 2018 economic analysis includes the capital costs associated with the winning bids, the costs associated with the Cedar Springs PPA, and updated net capacity factors. This economic analysis also captures terminal-value benefits from BTA and EPC-benchmark bids, where the Company retains control of the site at the end of the asset life. These benefits were considered in the 2017R RFP bid-selection process, consistent with the bid-evaluation methodology described in the RFP, and therefore, they are applied in the economic analysis.

Q. Please describe the load forecast included in the February 2018 economic analysis.

A. The economic analysis uses PacifiCorp's load forecast completed in the summer of 2017.

Q. Please explain how PacifiCorp used price-policy scenarios to analyze the Combined Projects.

A. In addition to assessing stochastic system cost risk, PacifiCorp analyzed the

Combined Projects under a range of price-policy assumptions regarding wholesale market prices and CO_2 policy. Wholesale-power prices, often set by natural-gas prices, and the system cost impacts of potential CO_2 policies influence the forecast of net system benefits from the Combined Projects. Wholesale-power prices and CO_2 policy outcomes affect the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect NPC benefits, non-NPC variable cost benefits, and system fixed-cost benefits of the Combined Projects. Because wholesale-power prices and CO_2 policy outcomes are both uncertain and important drivers to the analysis, PacifiCorp studied the economics of the Combined Projects under a range of different price-policy scenarios.

Q. What price-policy assumptions did PacifiCorp use in its February 2018 Combined Projects analysis?

A. PacifiCorp developed three wholesale-power price scenarios (low, medium, and high), and similarly developed three CO_2 policy scenarios (zero, medium, and high). The nine price-policy scenarios developed for the analysis reflect different combinations of these scenario assumptions.

Considering that there is a high level of correlation between wholesale-power prices and natural-gas prices, the wholesale-power price scenarios were based on a range of natural-gas price assumptions. This ensures consistency between power price and natural-gas price assumptions for each scenario. PacifiCorp implemented its CO_2 policy assumptions through a CO_2 price, expressed in dollars-per-ton recognizing that it is possible that future CO_2 policies targeting electric-sector emissions could be adopted and impose incremental costs to drive emission reductions. CO_2 price assumptions used in the price-policy scenarios are not intended to mimic a specific type of policy mechanism (*i.e.*, a tax or an allowance price under a cap-and-trade program), but are intended to recognize that there might be future CO_2 policies that impose a cost to reduce emissions.

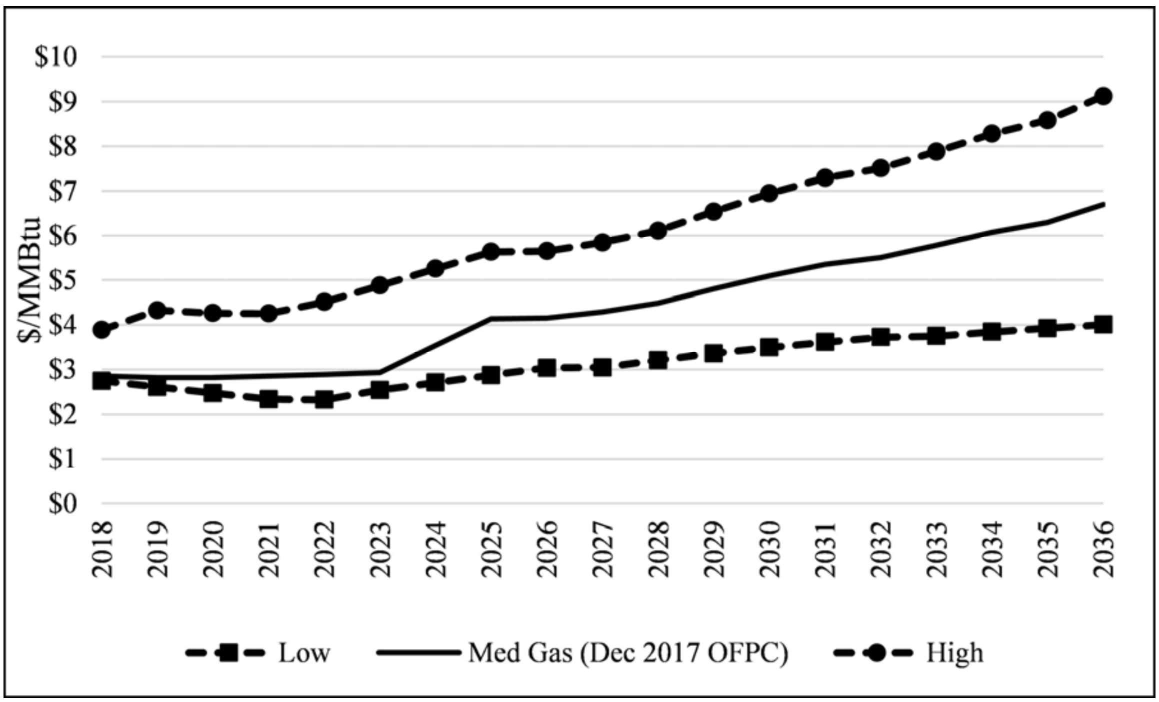
Q. Please describe the natural-gas price assumptions used in the February 2018 price-policy scenarios.

A. The medium-natural-gas price assumptions that are paired with zero CO_2 prices reflect natural-gas prices from PacifiCorp's official forward price curve (OFPC) dated December 29, 2017. This OFPC uses observed forward market prices as of December 29, 2017, for 72 months, followed by a 12-month transition to natural-gas prices based on a forecast developed by a third-party forecasting service. The medium-, low-, and high-natural-gas price assumptions used for all other scenarios were chosen after reviewing a range of credible third-party forecasts. Confidential Exhibit PAC/701 shows the range in natural-gas price assumptions from these third-party forecasts relative to those adopted for the price-policy scenarios to evaluate the Combined Projects.

The low-natural-gas price assumption was also derived from a low-price scenario developed by a third-party forecasting service. The medium-natural-gas price assumption, which is used beyond month 84 in the December 2017 OFPC, and in all months when medium-natural-gas prices are paired with medium or low CO_2 price assumptions, is based on a base-case forecast from [redacted] that is reasonably aligned with other base-case forecasts. The high-natural-gas price assumption was based on a high-price scenario from [redacted] that is characterized by exaggerated boom-bust cycles (cyclical periods of high prices and low prices). PacifiCorp smoothed the boom-bust cycle in this third party's high-price scenario because the specific timing of these cycles is extremely difficult to project with reasonable accuracy.

Figure 1 shows Henry Hub natural-gas price assumptions from the December 2017 OFPC, low-, and high-natural-gas price scenarios.

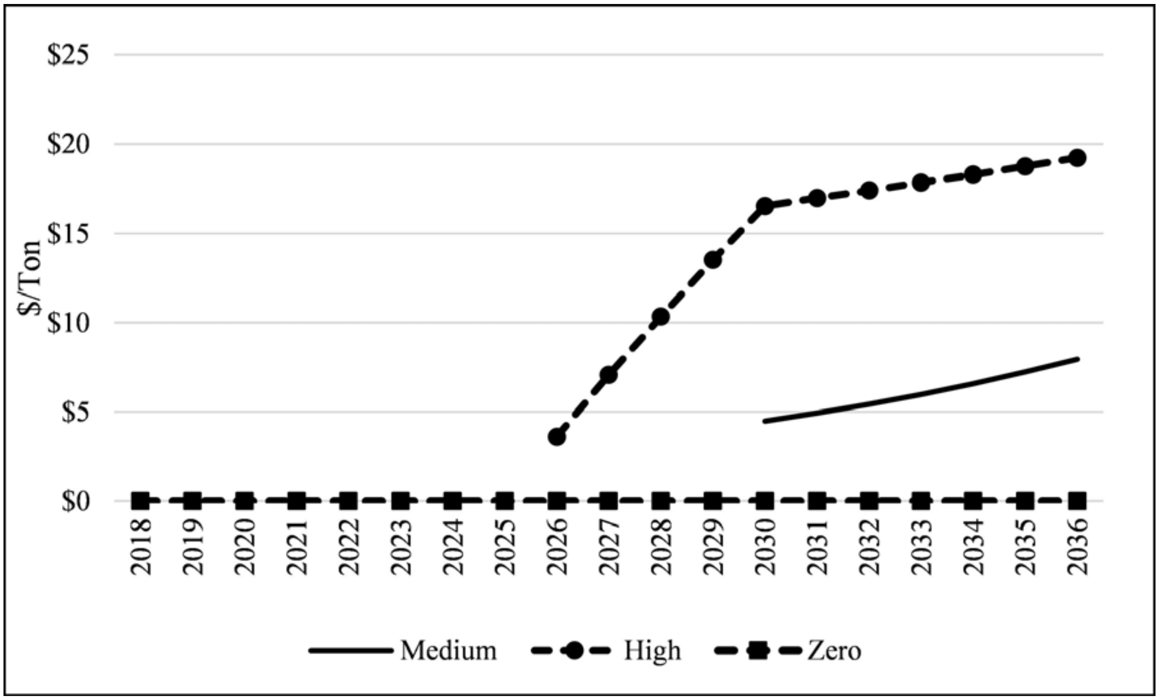
Figure 1. Nominal Natural-Gas Price Scenarios in the February 2018 Analysis



Q. **Please describe the CO_2 price assumptions used in the February 2018 price-policy scenarios.**

A. As with natural-gas prices, the medium and high CO_2 price assumptions are based on third-party projections from [redacted]. To bracket the low end of potential policy outcomes, PacifiCorp assumes there are no future policies adopted that would require incremental costs to achieve emissions reductions in the electric sector. In this scenario, the assumed CO_2 price is zero. Figure 2 shows the CO_2 price assumptions used to analyze the Combined Projects.

Figure 2. Nominal CO_2 Price Assumptions in the February 2018 Analysis



Q. How did PacifiCorp apply federal PTC benefits in its system modeling using the SO model and PaR configured to forecast system costs through 2036?

A. The February 2018 economic analysis through 2036 models the Combined Projects using nominal PTC benefits. When establishing the 2017R RFP final shortlist, PacifiCorp applied PTC benefits for applicable bids (BTAs and benchmark-EPC bids) on a nominal basis rather than on a levelized basis because this better reflects how the federal PTC benefits for these bids will flow through to customers. It also aligns the treatment of federal PTC benefits in the system modeling results extending out through 2036 with the nominal revenue requirement results extending out through 2050. This approach ensures the 2017R RFP bid selections from the SO model more accurately reflect the difference in how BTA and benchmark-EPC bids are expected to impact customer rates.

Q. Did PacifiCorp apply the revenue requirement associated with capital costs on a levelized basis in its system modeling using the SO model and PaR configured to forecast system costs through 2036?

A. Yes. When setting rates, revenue requirement from capital costs is depreciated over the book life of the asset, effectively spreading the cost of capital investments over the life of the asset. Because revenue requirement from capital projects is spread over the life of the asset in rates, these costs continue to be treated as a levelized cost in the SO model and PaR simulations. Levelization of capital revenue requirement is necessary in these models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. Without levelization, this potential distortion is driven by how capital costs are included in rate base over time. Capital revenue requirement is generally highest in the first year an asset is placed in service and declines over time as the asset depreciates.

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

A. No. While the up-front capital cost of the Transmission Projects will contribute to retail-customer rate base, the revenue requirement for these investments will be partially offset by incremental revenue from other transmission customers. The up-front transmission costs will flow into PacifiCorp's formula transmission rate under its OATT and generate revenue credits that offset a portion of these costs for retail customers.

PacifiCorp uses its transmission system to serve retail-customer load and to manage retail-customer NPC through off-system market sales and purchases and is the largest user of its transmission system. However, other transmission customers pay OATT-based transmission rates that generate revenue credits and offset the cost of PacifiCorp's transmission revenue requirement. As discussed in Mr. Vail's testimony, the Transmission Projects are considered network transmission assets under PacifiCorp's OATT and therefore will be included in PacifiCorp's transmission formula rate. Based on recent history, PacifiCorp assumed that these revenue credits will account for approximately 12 percent of PacifiCorp's transmission revenue requirement. Consequently, PacifiCorp's analysis assumes its retail customers pay 88 percent of the revenue requirement from the up-front capital cost for the Transmission Projects after accounting for an assumed 12 percent revenue credit from other transmission customers.

Q. How did PacifiCorp model de-rates to its Wyoming 230 kV transmission system when evaluating the Combined Projects?

A. In its final 2017 IRP resource-portfolio screening process, PacifiCorp identified and quantified reliability benefits associated with the Aeolus-to-Bridger/Anticline Line. This new transmission project will eliminate de-rates caused by outages on 230 kV transmission-system elements. Historical outages on this part of PacifiCorp's transmission system indicate an average de-rate of 146 MW over approximately 88 outage days per year, which equates to approximately one 146-MW, 24 hour outage every four days. Without knowing when these events might occur, de-rates on the existing 230 kV transmission system were captured in the SO model and PaR as a 36.5 MW reduction in the transfer capability from eastern Wyoming to the Aeolus area. In simulations that include the Combined Projects, this de-rate assumption was eliminated when the new transmission assets are placed in service at the end of October 2020.

Q. How did PacifiCorp model line-loss benefits associated with the Transmission Projects when performing its economic analysis of the Combined Projects?

A. Line-loss benefits are only applicable in those simulations where the Transmission Projects are built and therefore were only considered in the simulations that include the Combined Projects. When the Aeolus-to-Bridger/Anticline Line is added in parallel to the existing transmission lines, resistance is reduced, which lowers line losses. With reduced line losses, an incremental 11.6 average MW (aMW) of energy, which equates to approximately 102 gigawatt-hours (GWh), will be able to flow out of eastern Wyoming each year. The line-loss benefit was reflected in the SO model and PaR by reducing northeast Wyoming load by approximately 11.6 aMW each year.

Q. Did PacifiCorp analyze potential EIM benefits in its economic analysis of the Combined Projects?

A. Yes. In its final 2017 IRP resource-portfolio screening process, PacifiCorp described how the EIM can provide potential benefits when incremental energy is added to transmission-constrained areas of Wyoming. Unscheduled or unused transmission from participating EIM entities enables more efficient power flows within the hour. With increasing participation in the EIM, there will be increasing opportunities to move incremental energy from Wyoming to offset higher-priced generation in the PacifiCorp system or other EIM participants' systems. The more efficient use of transmission that is expected with growing participation in the EIM was captured in the economic analysis of the Combined Projects by increasing the transfer capability between the east and west sides of PacifiCorp's system by 300 MW (from the Jim Bridger plant to south-central Oregon). The ability to use intra-hour transmission from a growing list of EIM participants more efficiently is not driven by the Combined Projects; however, this increased connectivity provides the opportunity to move low-cost incremental energy out of transmission-constrained areas of Wyoming.

Q. Did PacifiCorp conduct additional sensitivity studies to assess the Combined Projects?

A. Yes. PacifiCorp completed sensitivity studies to assess how certain factors affect the net benefits of the Combined Projects. The first sensitivity compares the Combined Projects to potential solar resources, based on bids received in the 2017S RFP. The second sensitivity quantifies how the net benefits of the Combined Projects are affected when paired with the wind repowering project.

Annual Revenue Requirement Modeling Methodology

Q. In addition to the system modeling used to calculate present-value net benefits over a 20-year planning period, has PacifiCorp forecasted the change in nominal revenue requirement due to the Combined Projects?

A. Yes. The system PVRR from the SO model and PaR was calculated from an annual stream of forecasted revenue requirement over a 20-year time frame, consistent with the planning period in the IRP. The annual stream of forecasted revenue requirement captures nominal revenue requirement for non-capital items (*i.e.*, PTCs, NPC, fixed O&M, etc.) and levelized revenue requirement for capital expenditures. To estimate the annual revenue-requirement impacts of the Combined Projects, capital costs for the Wind Projects and the Transmission Projects need to be considered in nominal terms (*i.e.*, not levelized).

Q. How did PacifiCorp forecast the annual revenue-requirement impacts of the Combined Projects?

A. In the simulations that include the Combined Projects, the annual stream of costs for the Wind Projects, including levelized capital and PTCs, and the Transmission Projects are temporarily removed from the annual stream of costs used to calculate the stochastic-mean PVRR. The differential in the remaining stream of annual costs, which includes all system costs except for those associated with the Combined Projects, represents the net system benefit caused by the Combined Projects.

These data are disaggregated to isolate the estimated annual NPC benefits, other non-NPC variable-cost benefits (*i.e.*, variable O&M and emissions costs for those scenarios that include a CO_2 price assumption), and fixed-cost benefits. To complete the annual revenue-requirement forecast, the change in costs for the Combined Projects, including nominal capital revenue requirement and PTCs, are added back in with the annual system net benefits caused by the Combined Projects.

Q. Over what time frame did PacifiCorp estimate the change in annual revenue requirement due to the Combined Projects?

A. The change in annual revenue requirement was estimated through 2050. This captures the full 30-year life of the Wind Projects.

Q. What is the assumed life of the Transmission Projects?

A. PacifiCorp assumed a 62-year life for the Transmission Projects. The Transmission

Projects will continue to provide system benefits well beyond 2050 when the Wind Projects are fully depreciated. These additional benefits are not reflected in PacifiCorp's economic analysis.

Q. How did PacifiCorp calculate the annual net benefits caused by the Combined Projects beyond the 20-year forecast period used in PaR?

A. The PaR forecast period runs from 2017 through 2036. The change in net system benefits caused by the Combined Projects over the 2028-through-2036 time frame, expressed in dollars-per-MWh of incremental energy output from the Combined Projects, were used to estimate the change in system net benefits from 2037 through 2050. This calculation was performed in several steps.

First, the net system benefits caused by the Combined Projects were divided by the change in incremental energy expected from the Combined Projects, as modeled in PaR over the 2028-through-2036 time frame. Next, the net system benefits per MWh of incremental energy from the Combined Projects over the 2028-through-2036 time frame were levelized. These levelized results were extended out through 2050 at inflation. The levelized net system benefits per MWh of incremental energy output from the Combined Projects over the 2037-through-2050 time frame were then multiplied by the change in incremental energy output from the Combined Projects over the same period.

Q. Why did PacifiCorp use PaR results from the 2028-through-2036 time frame to extend system cost impacts out through 2050?

A. Consistent with the 2017 IRP, PacifiCorp's economic analysis of the Combined Projects assumes the Dave Johnston coal plant, located in eastern Wyoming, retires at the end of 2027. When this plant is assumed to retire, transmission congestion affecting energy output from resources in eastern Wyoming, where many repowered wind resources are located, is reduced. The incremental energy output from the Combined Projects provides more system benefits when not constrained by transmission limitations. Consequently, the net system benefits caused by the Combined Projects over the 2028-through-2036 time frame, after Dave Johnston is assumed to retire, is representative of net system benefits that could be expected beyond 2036.

Q. Did PacifiCorp calculate a PVRR(d) for the Combined Projects using its estimate of annual revenue requirement impacts projected out through 2050?

A. Yes.

System Modeling Price-Policy Results

Q. Please summarize the PVRR(d) results calculated in February 2018 from the SO model and PaR through 2036.

A. Table 1 summarizes the PVRR(d) results for each price-policy scenario. The PVRR(d) between cases with and without the Combined Projects, reflecting the updated final shortlist from the 2017R RFP, are shown for the SO model and for PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data used to calculate the updated SO Model PVRR(d) and PaR Stochastic Mean PVRR(d) results shown in the table are provided as Exhibit PAC/702.

Table 1. February 2018 SO Model and PaR PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Updated Final Shortlist		
	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	($185)	($150)	($156)
Low Gas, Medium CO_2	($208)	($179)	($188)
Low Gas, High CO_2	($370)	($337)	($355)
Medium Gas, Zero CO_2	($377)	($319)	($334)
Medium Gas, Medium CO_2	($405)	($357)	($386)
Medium Gas, High CO_2	($489)	$(448)	($469)
High Gas, Zero CO_2	($699)	($568)	($596)
High Gas, Medium CO_2	($716)	($603)	($633)
High Gas, High CO_2	($781)	($694)	($728)

Over a 20-year period, the Combined Projects reduce customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, when applying medium natural gas, medium CO_2 price-policy assumptions, the PVRR(d) net benefits range between $357 million, when derived from PaR stochastic-mean results, and $405 million, when derived from SO model results.

Q. What is the potential upside to these PVRR(d) results associated with REC value?

A. The PVRR(d) results presented in Table 1 do not reflect the potential value of RECs generated by the incremental energy output from the updated final shortlist projects. Accounting for the performance estimates from the updated final shortlist projects, customer benefits for all price-policy scenarios would improve by approximately $34 million for every dollar assigned to the incremental RECs that will be generated from the winning bids through 2036. Quantifying the potential upside associated with incremental REC values is simply intended to communicate that the net benefits from the winning bids could improve if the incremental RECs can be monetized in the market or otherwise used to offset higher cost purchases required to meet state renewable portfolio standard targets.

Q. Did you calculate the potential upside to these PVRR(d) results associated with reduced O&M costs?

A. Yes. Projects with large wind turbines are expected to require less O&M costs because there are fewer turbines on a given site. The default O&M assumptions applied to BTA and benchmark-EPC bids in the economic analysis are based on PacifiCorp's experience in operating and maintaining the existing fleet of owned-wind facilities, and do not reflect expected cost savings associated with operating and maintaining wind facilities proposing to use larger wind turbines. If the O&M cost elements applicable to the larger-turbine equipment are reduced by 42 percent, which is equivalent to an approximately 18-percent reduction in total O&M costs, beyond the proposed O&M agreement period, customer benefits calculated through 2036 for all price-policy scenarios would improve by approximately $19 million.

Q. Is there additional upside to the net benefits shown in Table 1?

A. Yes. PacifiCorp's analysis conservatively calculates net benefits by comparing a case with the Combined Projects against a case without the Combined Projects. As discussed by Mr. Vail, the Aeolus-to-Bridger/Anticline Line has been an integral component of PacifiCorp's long-term transmission plan for some time and it is unlikely that this investment would never be needed. The economic benefits would increase substantially if the case with the Combined Projects were compared to a case where the Aeolus-to-Bridger/Anticline line were added to the system at a later date. Further, the CO_2 price assumptions used in the updated economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. Consequently, the PVRR(d) net benefits in the six price-policy scenarios that use medium and high CO_2 price assumptions are conservative.

Revenue Requirement Modeling Price-Policy Results

Q. Please summarize the February 2018 PVRR(d) results calculated from the change in annual revenue requirement through 2050.

A. Table 2 summarizes the updated PVRR(d) results for each price-policy scenario calculated from the change in annual nominal revenue requirement through 2050. The annual data over the period 2017 through 2050 that was used to calculate the updated PVRR(d) results shown in the table are provided as Exhibit PAC/703.

Table 2. February 2018 Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Updated Final Shortlist
Low Gas, Zero CO_2	$184
Low Gas, Medium CO_2	$127
Low Gas, High CO_2	($147)
Medium Gas, Zero CO_2	($92)
Medium Gas, Medium CO_2	($167)
Medium Gas, High CO_2	($304)
High Gas, Zero CO_2	($448)
High Gas, Medium CO_2	($499)
High Gas, High CO_2	($635)

When system costs and benefits from the Combined Projects are extended out through 2050, covering the full depreciable life of the owned-wind projects included in the updated 2017R RFP final shortlist, the Combined Projects reduce customer costs in seven out of nine price-policy scenarios. Customer net benefits range from \$92 million in the medium natural-gas, zero CO_2 price-policy scenario to \$635 million in the high natural gas, high CO_2 price-policy scenario. Under the central price-policy scenario, when applying medium natural gas, medium CO_2 price-policy assumptions, the PVRR(d) benefits of the Combined Projects are \$167 million. The Combined Projects provide significant customer benefits in all price-policy scenarios, and the net benefits are unfavorable only when low natural-gas prices are paired with zero or medium CO_2 prices. These results show that upside benefits far outweigh downside risks.

Q. Is there additional potential upside to these PVRR(d) results associated with REC value?

A. Yes. The PVRR(d) results presented in Table 2 do not reflect the potential value of RECs generated by the incremental energy output from the Energy Vision 2020 Wind Projects. Accounting for the performance estimates from the updated final shortlist projects, customer benefits for all price-policy scenarios would improve by approximately \$43 million for every dollar assigned to the incremental RECs that will be generated from the winning bids through 2050.

Q. Is there additional potential upside to these PVRR(d) results associated with reduced O&M costs?

A. Yes. As discussed above, PacifiCorp anticipates O&M costs for those projects that will install larger-turbine equipment to be lower than what has been reflected in the updated economic analysis. Accounting for these cost savings, customer benefits for all price-policy scenarios would improve by approximately $31 million when calculated from projected operating costs through 2050.

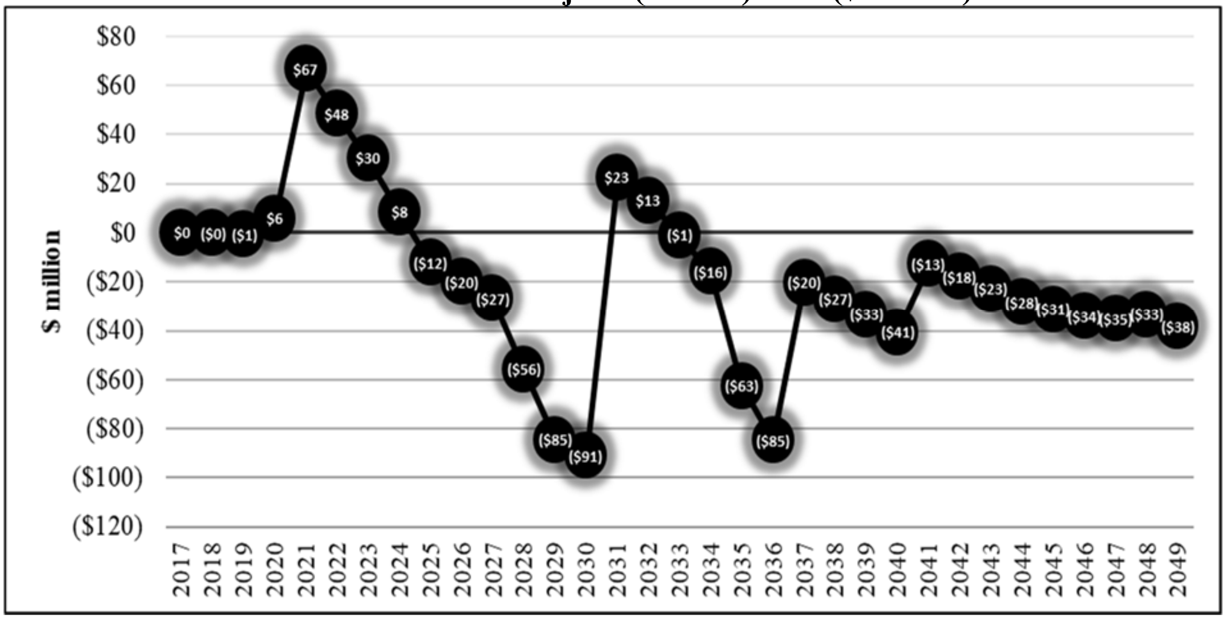
Q. Is there additional potential upside to these PVRR(d) results shown in Table 2?

A. Yes. As noted earlier, the economic benefits would increase substantially if the case with the Combined Projects were compared to a case where the Aeolus-to-Bridger/Anticline line were added to the system at a later date. Moreover, the updated CO_2 price assumptions used in the updated economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. Consequently, the PVRR(d) net benefits in the six price-policy scenarios that use medium and high CO_2 price assumptions are conservative.

Q. Please describe the change in annual nominal revenue requirement from the Combined Projects.

A. Figure 3 shows the change in nominal revenue requirement due to the Combined Projects for the medium natural gas, medium CO_2 price-policy scenario on a total-system basis. The change in nominal revenue requirement shown in the figure reflects February 2018 costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), O&M expenses, the Wyoming wind-production tax, and PTCs. The project costs are netted against system impacts from the Combined Projects, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the Combined Projects.

Figure 3. February 2018 Total-System Annual Revenue Requirement With the Combined Projects (Benefit)/Cost ($ million)



The Combined Projects produce net benefits in 23 years out of the 30 years that the proposed owned-wind resources selected to the 2017R RFP final shortlist are assumed to operate. The year-on-year reduction in net benefits from 2036 to 2037 is driven by the Company's conservative approach to extrapolate benefits from 2037 through 2050 based on modeled results from the 2028-through-2036 time frame. This leads to an abrupt reduction in the benefits in 2037, and a subsequent year-on-year reduction to net benefits, which breaks from the trend observed in the model results over the 2035-to-2036 time frame. This extrapolation methodology is conservative because it results in project benefits not matching the levels observed in the model results for 2036 until 2047.

Solar Sensitivity

Q. Did PacifiCorp include a solar sensitivity in its February 2018 analysis?

A. Yes. The solar sensitivity analysis reflects the updated final shortlist from the 2017R RFP and best-and-final pricing supplied by bidders participating in the 2017S RFP on February 1, 2018.

Q. Please describe the sensitivity studies that analyzed the impact of the solar bids received in the 2017S RFP on the economics of the Combined Projects.

A. The Company's solar sensitivity analysis used the SO model and PaR simulations to determine the PVRR(d) based on two model runs—one with solar PPA bids and the Combined Projects and one with solar PPA bids but without the Combined Projects.

Q. What were the results of the solar sensitivity where solar PPA bids are assumed to be pursued in lieu of the Combined Projects?

A. Table 3 summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued without any investments in the Combined Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 3. February 2018 Solar Sensitivity with Solar PPAs Included in lieu of the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	($343)	($405)	$61
PaR Stochastic Mean	($228)	($357)	$129
PaR Risk Adjusted	($237)	($386)	$149
Low Gas, Zero CO2			
SO Model	($196)	($185)	($11)
PaR Stochastic Mean	($139)	($150)	$11
PaR Risk Adjusted	($145)	($156)	$11

In this sensitivity, the SO model selects 1,122 MW of solar PPA bids in the low natural gas, zero CO_2 price-policy scenario and 1,419 MW of solar PPA bids in the medium natural gas, medium CO_2 price-policy scenario. All the selected solar PPA bids are for projects located in Utah.

In the medium natural gas, medium CO_2 price-policy scenario, a portfolio with the Combined Projects delivers greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects. Customer benefits are greater when the resource portfolio includes the Combined Projects without solar PPA bids by $149 million in the medium natural gas, medium CO_2 price-policy scenario based on the risk-adjusted PaR results. In the low natural gas, zero CO_2 price-policy scenario, the portfolio with the Combined Projects delivers slightly greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects when modeled in PaR, and slightly lower customer benefits when analyzed with the SO model. The decrease in net benefits in the solar PPA portfolio is $11 million based on the risk-adjusted PaR results.

When analyzed without the Combined Projects, the solar PPA bids produce net customer benefits that are lower than the benefits expected from the Combined Projects in the medium natural gas, medium CO_2 price-policy scenario. While the sensitivity with a portfolio containing solar PPAs without the Combined Projects produces PVRR(d) results that are similar to the PVRR(d) results with only the Combined Projects in the low natural-gas, zero CO_2 price-policy scenario, both portfolios deliver customer benefits. This sensitivity did not support an alternative resource procurement strategy to pursue solar PPA bids in lieu of the Combined Projects. This would leave the significant benefits from the Combined Projects, which include building a much-needed transmission line, on the table.

Q. What were the results of the solar sensitivity where solar PPA bids are pursued with the Combined Projects?

A. Table 4 summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued along with the proposed investments in the Combined Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 4. February 2018 Solar Sensitivity with Solar PPAs Included With the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	($647)	($405)	($242)
PaR Stochastic Mean	($519)	($357)	($163)
PaR Risk Adjusted	($543)	($386)	($157)
Low Gas, Zero CO2			
SO Model	($312)	($185)	($127)
PaR Stochastic Mean	($250)	($150)	($100)
PaR Risk Adjusted	($259)	($156)	($103)

In this sensitivity, the SO model continues to choose the winning bids included in the updated 2017R RFP final shortlist as part of the least-cost bid portfolio. In addition to these wind resource selections, the SO model selects 1,042 MW of solar PPA bids in the low natural gas, zero CO_2 price-policy scenario and 1,419 MW of solar PPA bids in the medium natural gas, medium CO_2 price-policy scenario. Again, all the selected solar PPA bids are for projects located in Utah.

When the solar PPAs are assumed to be pursued in addition to the Combined Projects, total net customer benefits increase. This result is consistent with PacifiCorp's expectation that cost-effective solar opportunities would not displace the Combined Projects but would only potentially add to incremental resource procurement opportunities that might provide net customer benefits.

Wind-Repowering Sensitivity

Q. Please explain PacifiCorp's February 2018 sensitivity analysis related to the wind repowering project.

A. The wind repowering sensitivity reflects the updated final shortlist and cost-and performance estimates for the wind repowering project as of February 2018. Table 5 summarizes PVRR(d) results for this wind-repowering sensitivity. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural-gas, medium CO_2 and the low natural-gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without wind repowering.

Table 5. Wind-Repowering Sensitivity (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	($608)	($405)	($204)
PaR Stochastic Mean	($541)	($357)	($184)
PaR Risk Adjusted	($567)	($386)	($181)
Low Gas, Zero CO2			
SO Model	($334)	($185)	($149)
PaR Stochastic Mean	($281)	($150)	($131)
PaR Risk Adjusted	($295)	($156)	($138)

In the February 2018 wind-repowering sensitivity, customer benefits increase significantly when the wind repowering project is implemented with the Combined Projects in both the medium natural-gas, medium CO_2, and the low natural-gas, zero CO_2 price-policy scenarios. These results demonstrate that customer benefits not only persist, but also increase, if both the wind-repowering project and the Combined Projects are completed.

Adjusted Economic Analysis Without Uinta Facility

Q. Please summarize the cost-and-performance attributes of the Wind Projects without Uinta.

A. With removal of the Uinta project, the total in-service capital cost for the remaining Energy Vision 2020 Wind Projects is approximately $[redacted], with a per-unit capital cost of $[redacted]/kilowatt (kW). In aggregate, the Energy Vision 2020 Wind Projects are expected to operate at a capacity-weighted average annual capacity factor of [redacted] percent.

Q. What is the nominal value of PTCs relative to the in-service capital cost of the Energy Vision 2020 Wind Projects without Uinta?

A. Over the first 10 years of operation, the Energy Vision 2020 Wind Projects that will be owned by PacifiCorp will generate over $1.2 billion in PTC benefits, which is nearly 103 percent of the in-service capital for these wind facilities.

Q. Did PacifiCorp update the February 2018 economic analysis of the Combined Projects based on the removal of the Uinta project?

A. Yes. First, PacifiCorp performed a spreadsheet analysis to estimate the high-level economic impact of removing the Uinta project. This spreadsheet analysis was performed for all nine price-policy scenarios previously described in my testimony. Consistent with the Company's previous economic analysis, these results are based on the methodology used in the Company's IRP through 2036 and using nominal revenue requirement projections through 2050.

Q. Please describe how you performed the high-level spreadsheet analysis.

A. Using data from the February 2018 economic analysis, I calculated the system benefits, including the Uinta Project, on a dollar-per-MWh basis for each price-policy scenario. I then multiplied these results by the expected generation from the Uinta project to estimate the annual system benefits associated with the Uinta project in total dollars. These system-benefit estimates were then netted against the same project-specific costs for the Uinta facility that were used in the February 2018 economic analysis. This calculation results in an estimate of the marginal net benefit or cost of removing the Uinta project for each price-policy scenario.

Q. Did you also update the February 2018 economic analysis using PacifiCorp's models?

A. Yes. I also re-ran PacifiCorp's IRP models to remove Uinta under the medium natural gas, medium CO_2 and low natural gas, zero CO_2 price-policy scenarios.

Q. Did you update any of the other inputs used in the analysis?

A. No. Other than removing Uinta, all the other inputs used in the economic analysis are the same as the inputs used in the February 2018 analysis.

Q. What is the high-level estimate of the economic impact of removing Uinta based on results through 2036?

A. Table 6 reports the high-level estimate of the economic impact of removing Uinta based on the results through 2036. These PVRR(d) results are shown alongside the results summarized in my February 2018 economic analysis. The difference between the original results that include Uinta and the high-level estimates without Uinta are an indicator of the marginal net benefit or cost of the Uinta project.

Table 6. Estimated Impact of Removing Uinta
PaR Stochastic Mean PVRR(d) (Benefit)/Cost ($ million) through 2036

Price-Policy Scenario	February 2018 (With Uinta)	High-Level Estimate (Without Uinta)	Marginal (Benefit)/Cost of Uinta
Low Gas, Zero CO_2	($150)	($146)	($4)
Low Gas, Medium CO_2	($179)	($172)	($7)
Low Gas, High CO_2	($337)	($312)	($25)
Medium Gas, Zero CO_2	($319)	($296)	($23)
Medium Gas, Medium CO_2	($357)	($330)	($27)
Medium Gas, High CO_2	($448)	($410)	($38)
High Gas, Zero CO_2	($568)	($517)	($51)
High Gas, Medium CO_2	($603)	($548)	($55)
High Gas, High CO_2	($694)	($629)	($66)

Q. What conclusions can you draw from the results provided in Table 6?

A. The high-level estimate based on results through 2036 shows that net benefits of the Combined Projects (without Uinta) are reduced by between $4 million and $66 million. In the medium natural gas, medium CO_2 price-policy scenario, net benefits are reduced by $27 million. Considering that results from the IRP models were used to select winning bids in the 2017R RFP, these findings confirm that it was reasonable to include Uinta in the 2017R RFP final shortlist. Importantly, these results also show that the Combined Projects will continue to deliver substantial net customer benefits with removal of the Uinta project. With Uinta removed, the net benefits from the Combined Projects range between $146 million and $629 million. In the medium natural gas, medium CO_2 price-policy scenario, the net benefits are estimated to be $330 million.

Q. What is the high-level estimate of the economic impact of removing Uinta based on nominal revenue requirement results through 2050?

A. Table 7 reports the high-level estimate of the economic impact of removing Uinta based on the nominal revenue requirement results through 2050. These PVRR(d) results are shown alongside the February 2018 economic analysis. Like Table 6 above, the difference between the original results that include Uinta and the high-level estimates without Uinta are an indicator of the marginal net benefit or cost of the Uinta project.

Table 7. Estimated Impact of Removing Uinta
Nominal PVRR(d) (Benefit)/Cost ($ million) through 2050

Price-Policy Scenario	February 2018 (With Uinta)	High-Level Estimate (Without Uinta)	Marginal (Benefit)/Cost of Uinta
Low Gas, Zero CO_2	$184	$146	$38
Low Gas, Medium CO_2	$127	$97	$31
Low Gas, High CO_2	($147)	($145)	($2)
Medium Gas, Zero CO_2	($92)	($97)	$5
Medium Gas, Medium CO_2	($167)	($162)	($4)
Medium Gas, High CO_2	($304)	($283)	($20)
High Gas, Zero CO_2	($448)	($411)	($37)
High Gas, Medium CO_2	($499)	($456)	($43)
High Gas, High CO_2	($635)	($576)	($59)

Q. What conclusions can you draw from Table 7?

A. The high-level estimate based on nominal revenue requirement results through 2050 shows that removal of Uinta reduces the net cost of the Combined Projects in three of the nine price-policy scenarios, and that the net benefits of the Combined Projects are reduced in six of the nine price-policy scenarios. In the medium natural gas, medium CO_2 price-policy scenario, net benefits are reduced by $4 million. Importantly, when the impact of net benefits are based on nominal revenue requirement results through 2050, these results show that the Combined Projects will continue to deliver substantial net customer benefits with removal of the Uinta project. With Uinta removed, the net benefits from the Combined Projects in the scenarios where they occur range between \$97 million and \$576 million. In the medium natural gas, medium CO_2 price-policy scenario, the net benefits are estimated to be \$162 million.

Q. What is the economic impact of removing Uinta based on updated results from the IRP model runs?

A. Table 8 reports the high-level estimate of the economic impact of removing Uinta alongside the updated modeled results using the 2036 and 2050 calculation methodologies. These results are presented for both the low natural gas, zero CO_2 and the medium natural gas, medium CO_2 price-policy scenarios. The table also shows the difference between the high-level estimate and the modeled results.

Table 8. Estimated Impact of Removing Uinta
Nominal PVRR(d) (Benefit)/Cost (\$ million) through 2050

PaR Stochastic Mean PVRR(d) (Benefit)/Cost (\$ million) through 2036			
Price-Policy Scenario	**High-Level Estimate**	**Modeled Result**	**Variance from**
Low Gas, Zero CO_2	(\$146)	(\$143)	(\$3)
Medium Gas, Medium CO_2	(\$330)	(\$338)	\$8
Nominal PVRR(d) (Benefit)/Cost (\$ million) through 2050			
Price-Policy Scenario	**High-Level Estimate**	**Modeled Result**	**Variance from**
Low Gas, Zero CO_2	\$146	\$154	(\$8)
Medium Gas, Medium CO_2	(\$162)	(\$174)	\$12

Q. What conclusions can you draw from Table 8?

A. First, the modeled results are similar to the high-level estimates described above, and consequently, the high-level estimates provide a reasonable representation of the impact of removing Uinta.

Second, under the medium natural gas, medium CO_2 price-policy scenario, the Combined Projects still provide net customer benefits when Uinta is removed. When calculated from IRP model results through 2036, customer net benefits are \$338 million (down by \$19 million from \$357 million in the February 2018 analysis).

When calculated from the nominal revenue requirement results through 2050, customer net benefits are $174 million (up by $7 million from the $167 million in the February 2018 analysis).

Third, under the low natural gas, zero CO_2 price-policy scenario, the Combined Projects still provide net customer benefits with Uinta removed when the PVRR(d) is calculated from IRP model results through 2036. Based on this methodology, customer net benefits are $143 million (down by $7 million from the $150 million benefit in the February 2018 analysis). When calculated from the nominal revenue requirement results through 2050, net costs are $154 million (down by $30 million from the $184 million in the February 2018 economic analysis).

Q. Have you calculated the change in capital costs that would have to occur to eliminate net benefits in the medium natural gas, medium CO_2 price-policy scenario?

A. Yes. Removal of the Uinta project reduces capital costs for the Combined Projects to [redacted]. In-service capital costs would have to increase by approximately 11.1 percent (or [redacted]) to eliminate net benefits in the medium natural gas, medium CO_2 price-policy scenario.

Q. Do the Combined Projects without Uinta still provide overall customer net benefits?

A. Yes. As set forth above, when using the IRP modeling, the Combined Projects still provide robust customer net benefits under all nine price-policy scenarios. Although the benefits have decreased slightly, they remain substantial. In addition, under the nominal revenue requirement view, the net benefits remained fairly consistent, increasing in some price-policy scenarios and decreasing in others. Although neither view is dispositive, each of these views provides important insight into how the Combined Projects are expected to impact the Company's revenue requirement. Taken together, each of these views indicate that the removal of Uinta does not adversely impact the customer benefits, and the acquisition of the Combined Projects remains in the public interest.

IV. WIND REPOWERING OF FOOTE CREEK I

Q. Please briefly describe what repowering a wind facility entails.

A. Repowering a wind facility involves upgrading an existing, operating wind facility with longer blades and new technology to generate more energy in a wider range of conditions.

Q. Please describe the scope of PacifiCorp's full repowering project.

A. The full wind repowering project includes 13 wind facilities, representing approximately 1,040 MW of installed wind capacity. PacifiCorp's underlying economic analysis described in my direct testimony in dockets UE 352 and UE 369 covers 12 of the 13 wind facilities, totaling approximately 999.1 MW—Glenrock I, Glenrock III, Rolling Hills,[51] Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, and Dunlap in Wyoming; Marengo I, Marengo II and Goodnoe

[51] Rolling Hills is not included in Oregon rates. *See In the Matter of PacifiCorp, dba Pacific Power, 2009 Renewable Adjustment Clause Schedule 202*, Docket No. UE 200, Order No. 08-548, at 20 (Nov. 14, 2008).

Hills in Washington; and Leaning Juniper in Oregon.[52] This filing includes the 13th facility, Foote Creek I in Wyoming, which presents similar economic benefits, as described further below.

Q. Is PacifiCorp seeking recovery for the full scope of its repowering project in this general rate case (GRC)?

A. No. In docket UE 352, the Commission approved a stipulation providing recovery through the RAC for most of the repowered wind facilities—Glenrock I, Goodnoe Hills, High Plains, Leaning Juniper, Marengo I, Marengo II, McFadden Ridge, Seven Mile Hill I, and Seven Mile Hill II.[53] PacifiCorp is separately seeking approval for Glenrock III and Dunlap in its 2020 RAC filing in docket UE 369, with requested rate effective dates of April 1, 2020, and October 15, 2020, respectively, for those facilities.[54] Therefore, PacifiCorp only seeks rate recovery in this general rate case for the single remaining wind facility, Foote Creek I, expected to be in service in late 2020. Table 9 depicts the full scope of PacifiCorp's repowering project, organized by the mechanism through which PacifiCorp has sought cost recovery approval.

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[52] *In the Matter of PacifiCorp, dba Pacific Power, 2020 Renewable Adjustment Clause*, Docket No. UE 369, PAC/300, Link/30-56 (Nov. 20, 2019); *In the Matter of PacifiCorp, dba Pacific Power, 2019 Renewable Adjustment Clause*, Docket No. UE 352, PAC/300, Link/29-55 (Dec. 28, 2018).
[53] Docket No. UE 352, Order No. 19-304, at 8 (Sept. 16, 2019) (approving stipulation).
[54] Docket No. UE 369, PAC/100, Lockey/5 (Nov. 20, 2019).

Table 9. Repowered Wind Facilities, by Cost Recovery Mechanism

Cost Recovery Mechanism:	Wind Facility	Online Date	Location	Installed Capacity (MW)
2019 RAC	Glenrock I	Online	WY	99.0
	Seven Mile Hill I	Online	WY	99.0
	Seven Mile Hill II	Online	WY	19.5
	High Plains	Online	WY	99.0
	McFadden Ridge	Online	WY	28.5
	Marengo I	Online	WA	140.4
	Marengo II	Online	WA	70.2
	Goodnoe Hills	Online	WA	94.0
	Leaning Juniper	Online	OR	100.5
2020 RAC	Glenrock III	Online	WY	39.0
	Dunlap	Mid-2020	WY	111.0
2021 GRC	Foote Creek I	Late 2020	WY	31
n/a[55]	Rolling Hills	Online	WY	99.0

Q. What are the general benefits of the repowering project?

A. Repowering upgrades will increase output of the wind facilities included in Oregon rates by 28.1 percent on average, extend the operating lives of the facilities, and allow the facilities to requalify for federal PTCs for 10 additional years.

Q. What were the results of PacifiCorp's underlying economic analysis for the full repowering project?

A. PacifiCorp developed economic analysis in February 2018, updated in August 2018, which demonstrated significant customer benefits across a range of assumptions related to forward market prices and possible federal CO_2 policy.[56]

Q. Did PacifiCorp analyze repowering in its 2017 IRP?

A. Yes. The preferred portfolio in the 2017 IRP, representing PacifiCorp's risk-adjusted, least-cost plan to meet customer demand reliably over a 20-year planning period,

[55] As noted above, Rolling Hills is not included in Oregon rates.
[56] Docket No. UE 369, PAC/300, Link/30-56; Docket No. UE 352, PAC/300, Link/29-55.

includes repowering 905 MW of existing wind resource capacity located in Oregon, Washington, and Wyoming. PacifiCorp later expanded the scope of the wind repowering project to include its Goodnoe Hills and Foote Creek I wind facilities, both of which PacifiCorp determined could be economically repowered similar to the facilities evaluated in the 2017 IRP. This increased the wind repowering project to approximately 1,040 MW of existing wind capacity.

Q. Did the Commission acknowledge repowering action items in PacifiCorp's 2017 IRP?

A. Yes. In Order 18-138, the Commission acknowledged the 2017 IRP, including the action items related to PacifiCorp's Energy Vision 2020 projects (which includes repowering along with the Combined Projects discussed above), with conditions.[57]

Q. Please describe the repowering of the Foote Creek I facility.

A. As discussed in PacifiCorp witness Mr. Timothy J. Hemstreet's testimony, the Foote Creek I wind facility was originally developed more than 20 years ago. Because of its age and design, repowering of Foote Creek I involves the removal of all existing wind turbine equipment, including towers, foundations, and energy collection systems, and replacement with new equipment and energy collector circuits appropriately sized for the new equipment. This is different from repowering the rest of PacifiCorp's wind fleet, where the existing towers, foundations, and energy collection systems remained in place and were able to accommodate more modern wind-turbine-generator equipment.

Repowering at the Foote Creek I facility will result in the replacement of

[57] Order No. 18-138 at 7-8.

68 existing small-capacity wind turbines with 13 modern wind turbines, representing approximately 46 MW of wind resource nameplate capacity.

Q. Why wasn't Foote Creek I included in your main economic analysis?

A. As discussed above, the scope of repowering the Foote Creek I facility is notably different than the other wind facilities. Moreover, unlike the other 12 wind facilities within the scope of the wind repowering project, PacifiCorp shared ownership of Foote Creek I with Eugene Water & Electric Board (EWEB). Further differentiating Foote Creek I from the other 12 wind facilities within the scope of the wind repowering project, Bonneville Power Administration (BPA) was purchasing 37 percent of the output from Foote Creek I via a PPA that was to terminate in April 2024. Taken together, it took additional time to engage in discussions with EWEB and BPA to determine whether the ownership structure and PPA could be modified to facilitate repowering the Foote Creek I wind facility. Ultimately, as Mr. Hemstreet describes in his testimony, PacifiCorp was able to clear the way for repowering by acquiring EWEB's ownership interest, terminating the PPA with BPA, and acquiring the master wind energy lease rights associated with the Foote Creek I site.

Q. When did PacifiCorp make the decision to repower Foote Creek I?

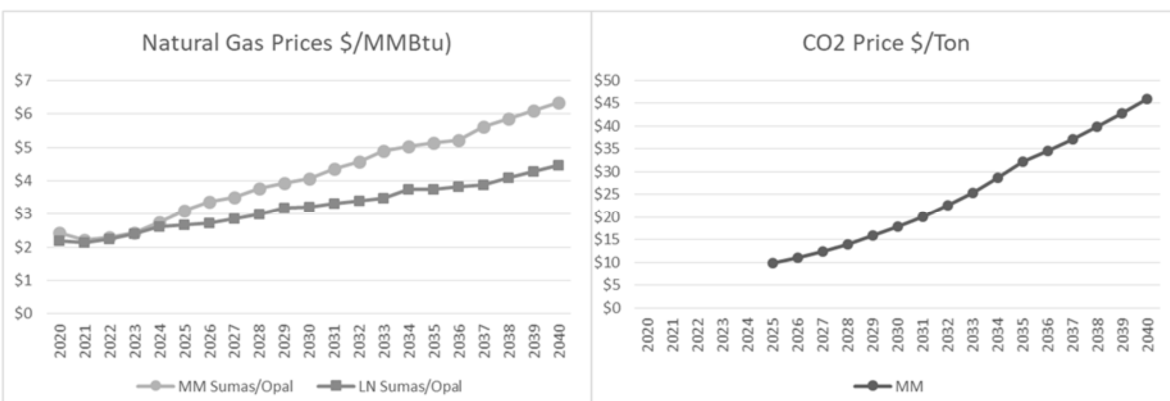
A. PacifiCorp made the decision to repower Foote Creek I in June 2019.

Q. Please summarize the economic analysis that supports the prudence of this decision.

A. PacifiCorp originally approved repowering Foote Creek I based on a June 11, 2019, economic analysis indicating that repowering would produce present-value net customer benefits ranging between $3 million and $46 million. This analysis included acquisition of EWEB's 21.21 percent ownership interest and termination of the PPA with BPA. This analysis did not include acquisition of the master wind energy lease rights associated with the Foote Creek I site.

The economic analysis was updated July 16, 2019, to reflect the acquisition of the master wind energy lease rights associated with the Foote Creek I site. This analysis used two price-policy scenarios, representing low and medium natural gas prices and zero and medium CO_2 price scenarios. The price-policy scenario that pairs medium natural gas prices with medium CO_2 prices is referred to as the "MM" scenario and the price-policy scenario that pairs low natural gas prices with a zero CO_2 price is referred to as the "LN" scenario. The natural gas and CO_2 price assumptions are summarized in Figure 4.

Figure 4. Price-Policy Assumptions used in the Economic Analysis of Foote Creek I Repowering.



My analysis shows that Foote Creek I will deliver net customer benefits in both price-policy scenarios through 2050, producing present-value net customer benefits ranging between $6 million and $48 million.

Q. Please explain how you conducted your analysis.

A. The methodology is consistent with the approach used to perform the economic analysis of the other 12 facilities within the scope of the wind repowering project and the Combined Projects described in Section III of my testimony. The system value of incremental wind energy in eastern Wyoming is calculated from two PaR simulations for a given price-policy scenario—one simulation with incremental wind energy and one simulation without incremental wind energy. I then converted the system value of incremental wind energy to a dollar-per-megawatt-hour value by dividing the change in annual system costs by the change in incremental wind energy for both price-policy scenarios through 2038. The value of wind energy is extended out through 2050 by extrapolating the system values calculated from modeled data over the 2030-to-2038 time frame. The assumed system value, expressed in dollars per megawatt-hour, is applied to the incremental energy output associated with Foote Creek I wind repowering.

Q. Please provide the results of your analysis.

A. Foote Creek I repowering is forecasted to provide significant net benefits for customers. Table 10 summarizes the benefits calculated from changes in system costs through 2050, inclusive of the cost of repowering. This table also presents the same information on a levelized dollar-per-megawatt-hour basis. Under the medium and low price-policy scenarios, nominal levelized net benefits are $29/MWh and $3/MWh, respectively. These results are consistent with the range of the net benefits associated with other wind repowering facilities presented in my direct testimony in PacifiCorp's RAC filings in dockets UE 352 and UE 369.[58]

[58] Docket No. UE 352, PAC/300, Link/34, 54 (Tables 5 and 16); Docket No. UE 369, PAC/300, Link/35, 55 (Tables 5 and 16).

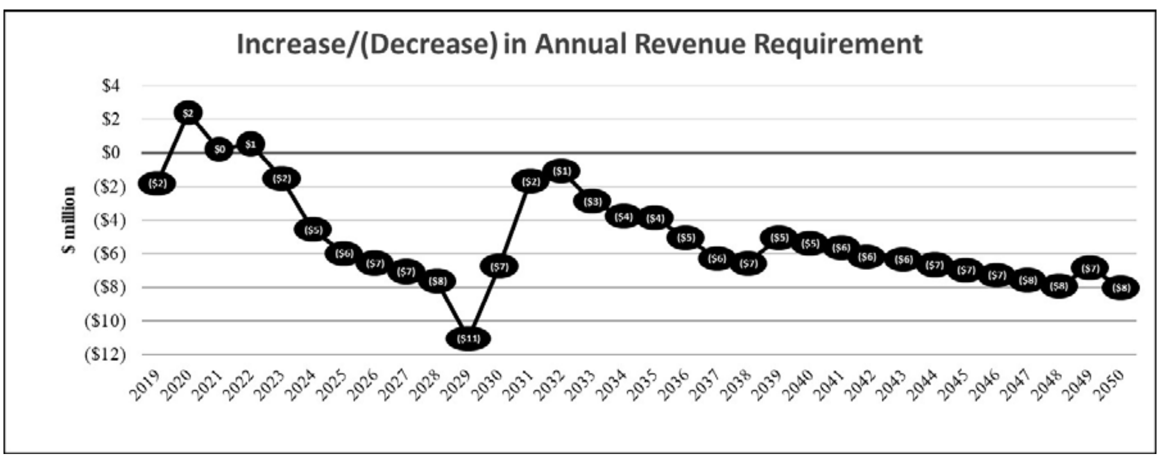
Table 10. Net Benefits from Foote Creek I Repowering

	PVRR(d) Net (Benefit)/Cost ($ million)	Nom. Lev. Net Benefit ($/MWh of Incremental Energy)
Medium Natural Gas, Medium CO_2	($48.2)	$29/MWh
Low Natural Gas, No CO_2	($5.6)	$3/MWh

Q. Have you demonstrated the estimated change in nominal annual revenue requirement from Foote Creek I repowering for the medium price-policy scenario?

A. Yes. Figure 5 reflects the change in nominal revenue requirement associated with project costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), O&M expenses, the Wyoming wind-production tax, and PTCs. The project costs are netted against system benefits as described above. Foote Creek I repowering reduces nominal revenue requirement in all but the first three years of its depreciable life.

Figure 5. (Reduction)/Increase in Total-System Annual Revenue Requirement from Foote Creek I Repowering



V. PRYOR MOUNTAIN WIND PROJECT

Q. Did you conduct the economic analysis supporting acquisition of the Pryor Mountain Wind Project?

A. Yes. I prepared the economic analysis for the 240 MW Pryor Mountain Wind Project, which supports PacifiCorp's decision to move forward with the project as a resource decision that is least-cost and least-risk for customers. I completed this analysis in September 2019.

Q. Please provide background on the Pryor Mountain Wind Project.

A. In May 2019, PacifiCorp executed an agreement for the development rights associated with the Pryor Mountain Wind Project, located in Montana. In June 2019, PacifiCorp and Vitesse, LLC (Vitesse) (a wholly-owned subsidiary of Facebook, Inc.) executed an agreement for the purchase of all RECs generated by Pryor Mountain over a 25-year period under PacifiCorp's Oregon Schedule 272 – Renewable Energy Rider Optional Bulk Purchase Option. In September 2019, PacifiCorp executed the EPC and wind turbine supplier agreements for the project. Mr. Teply provides additional information about this project in his testimony.

Q. Was the Pryor Mountain Wind Project the result of an RFP issued by PacifiCorp?

A. No. PacifiCorp pursued the Pryor Mountain Wind Project outside of an RFP because it was a unique, time sensitive opportunity to provide significant value to customers. The opportunity evolved over a very compressed timeline, beginning in October 2018, with final terms on all material agreements completed before September 30, 2019. Therefore, consistent with the Commission's rules governing resource procurement for electric companies, PacifiCorp filed a report on September 27, 2019, explaining the relevant circumstances leading to the acquisition of this resource and the value this resource provides to customers.[59]

Q. Did Staff provide comments on this report?

A. Yes. Staff filed response comments in docket LC 70 on October 25, 2019.[60] Staff raised several high-level concerns, which it asked PacifiCorp to address in seeking rate recovery for this facility.

Q. Can you address Staff's concern regarding whether this facility is a time-limited opportunity of unique value based on the project economics provided in PacifiCorp's report?

A. Yes. In response to Staff's general concern that it could not assess the project's economics without an opportunity to evaluate PacifiCorp's economic modeling inputs and workpapers, my testimony and exhibits provide the information necessary for Staff's evaluation. Staff also raised one specific concern regarding the project's economics, which relates to the benefits modeled in 2050, the final year of the analysis. Staff expressed concern that these 2050 benefits could be an "un-realistic end effect in PacifiCorp's modeling" which skews the outcome.[61] Staff claims that, in the low natural gas price and no CO_2 price assumption (the "LN" price-policy scenario), elimination of the benefits modeled in 2050 could turn any expected benefits into net costs.[62]

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[59] OAR 860-089-0100(3)(b), (4); *In the Matter of PacifiCorp, dba Pacific Power, 2019 Integrated Resource Plan*, Docket No. LC 70, PacifiCorp's Notice of Exception Under OAR 860-089-0100 (Sept. 27, 2019).
[60] Docket No. LC 70, Comments on PacifiCorp's September 27, 2019 Notice of Exception to the Competitive Bidding Rules (Oct. 25, 2019) ("Staff Exception Response Comments").
[61] *Id.* at p. 3.
[62] *Id.* at p. 3.

Q. Please explain the benefits modeled in 2050.

A. The modeling reflects a terminal value benefit because PacifiCorp retains control of the site at the end of the asset life. The terminal value benefit recognizes the fact that at end of a utility-owned resource's life, there is residual value that accrues to customers. For a PPA, the terminal value accrues to the project owner, not customers. That terminal value includes the facilities supporting the resources, like transmission facilities, that have longer useful lives and, in the case of generation tied to natural resources such as wind resources, there is inherent value in the site itself—particularly resources located in high-capacity-factor geographic areas like Montana. High-value, renewable-resource locations are often scarce or unique in their suitability for generation permitting and construction, as well as proximity to transmission.

Q. Has the Commission previously acknowledged that utilities generally include terminal value in their bids for benchmark resource in an RFP?

A. Yes, that is my understanding.[63]

Q. Staff suggests that the inclusion of the 2050 benefit is substantial enough to change the results of the economic analysis.[64] Please respond.

A. Contrary to Staff's claim, the analysis does not rely heavily on 2050 results to demonstrate a positive net benefit. Even if the terminal value were completely eliminated, which would not be appropriate, project customer net benefits under medium natural gas and CO_2 price-policy assumptions would range between

[63] *In the Matter of Public Utility Commission of Oregon Investigation Regarding Competitive Bidding,* Docket No. UM 1182, Order No. 14-149 (April 30, 2014).
[64] Staff Exception Response Comments at p. 3.

$57 million and $70 million.

Q. Staff also raised concerns about the need to protect customers against risks regarding possible construction delays and PTC ineligibility, lower-than-expected capacity factors, and the potential for PTC renewal making this opportunity relatively less valuable compared to potential future wind resources.[65] Please respond.

A. None of the potential risk factors Staff identifies detract from the customer benefits of the Pryor Mountain Wind Project. First, as Mr. Teply describes, the Pryor Mountain Wind Project is on schedule to be in service by December 31, 2020, and meets all other requirements for 100 percent PTC benefits. Second, as evident in PacifiCorp's net power cost model sponsored by Mr. David G. Webb in the concurrently filed Transition Adjustment Mechanism, PacifiCorp has modeled the Pryor Mountain Wind Project in rates using the same capacity factor I have used in my economic analysis—ensuring that customers will receive PTC and net power cost benefits based on the projected capacity factor. Third, the 100 percent PTC has not been renewed at this time, nor is there any certainty that it will be in the future. This is evident in the significant wind development now ongoing in the industry to meet the 2020 PTC deadline.

Q. Staff also raised a concern about the use of Schedule 272 in connection with the Pryor Mountain Wind Project.[66] Please respond.

A. The Schedule 272 Agreement represents a unique opportunity to leverage Vitesse's desire to purchase RECs from a specified resource while providing a cost-effective

[65] *Id.* at p. 4.
[66] *Id.* at p. 5.

energy resource to serve PacifiCorp's customers. The Company estimates that the present-value cost reduction resulting from Vitesse's purchase of all RECs generated by the project is $[redacted], which will mitigate risks under the various price-policy assumptions.

Q. Finally, Staff suggested that customers like Vitesse should be made aware of other voluntary green products as an alternative to Schedule 272.[67] How do you respond?

A. PacifiCorp offers voluntary REC purchase options through its Blue Sky program, including the bulk REC purchase option authorized by Schedule 272. Staff suggests that community solar is a voluntary product available to PacifiCorp customers. While this is true, I note that a program like community solar, on its own, is unlikely to meet the needs of a customer like Vitesse that is seeking to "green" a significant quantity of energy consumption. PacifiCorp is not aware of any barriers to accessing information regarding any of PacifiCorp's voluntary product options, particularly for large, sophisticated customers like Vitesse.

Q. Please describe your economic analysis of the Pryor Mountain Wind Project.

A. The methodology I used to perform the economic analysis of the Pryor Mountain Wind Project is the same I used to perform the economic analysis of the other resources addressed in my testimony. I relied on PaR runs with a simulation period covering the 2019-to-2038 time frame. System benefits from the development of the Pryor Mountain Wind Project, which includes sale of the associated RECs in accordance with the Schedule 272 Agreement, are based on two PaR simulations—

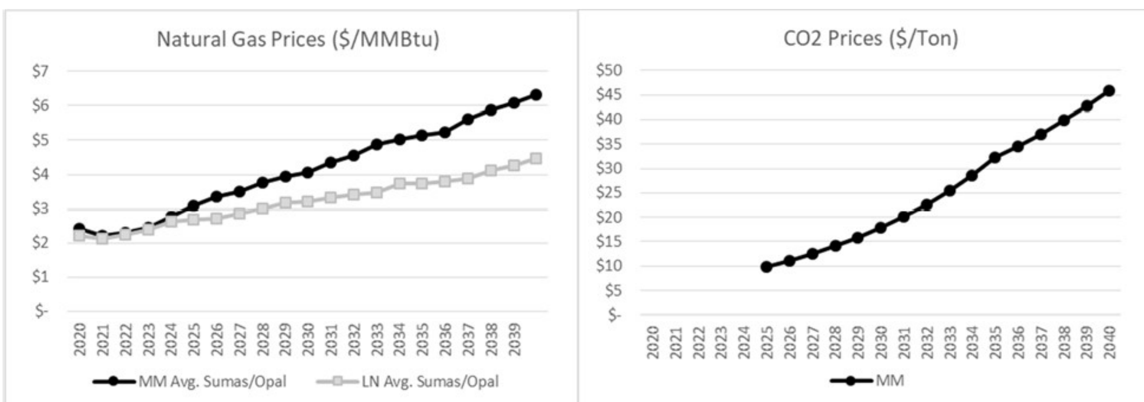
[67] *Id.* at p. 5.

one with incremental generation from the project and one without incremental generation from the project.

Q. What price-policy scenarios did you use in your economic analysis?

A. I used the same two price-policy scenarios as in PacifiCorp's project-by-project wind repowering analysis and for Foote Creek I—one assuming medium natural gas price and medium CO_2 price assumptions (the "MM" price-policy scenario) and one assuming low natural gas price and no CO2 price assumptions (the "LN" price-policy scenario). These assumptions are summarized in Figure 6.

Figure 6. Price-Policy Assumptions in the Economic Analysis of the Pryor Mountain Wind Project



Q. Over what period did you analyze the costs and benefits of the Pryor Mountain Wind Project?

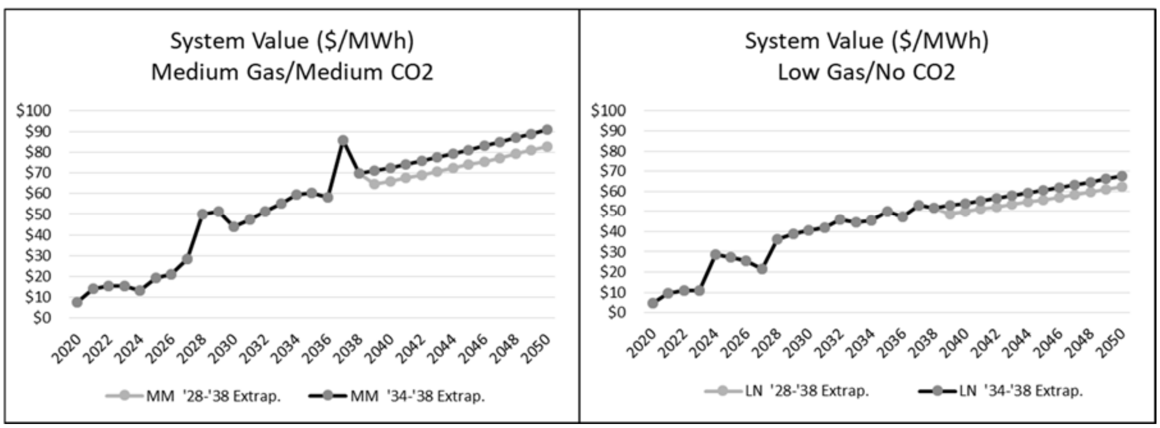
A. My analysis covers the 30-year life of the asset—from 2020 through 2050.

Q. Please explain how you developed a forecast of the project's benefits beyond the 2038 time frame.

A. As with my economic analysis of the Combined Projects and Foote Creek I, the system value of incremental energy is converted to a dollar-per-MWh value by dividing the reduction in annual system costs associated with the Pryor Mountain

Wind Project by the change in incremental energy from the Pryor Mountain Wind Project. This analysis was performed for the MM and LN price-policy scenarios through 2038. The value of energy is extended out through 2050 by extrapolating the system values calculated from modeled data over two different time frames—2028-to-2038, and 2024-to-2038. The assumed system value, expressed in dollars-per-megawatt-hour, is applied to the incremental energy output from Pryor Mountain Wind Project. The system value of the Pryor Mountain Wind Project is summarized for both price-policy scenarios in Figure 7.

Figure 7. System Value Used in the Economic Analysis of Pryor Mountain Wind Project



Q. Please provide the results of your economic analysis.

A. The Pryor Mountain Wind Project is expected to provide significant net benefits for customers. Table 11 summarizes the PVRR(d) benefits calculated from changes in system costs through 2050.[68] This table also presents the same information on a levelized dollar-per-megawatt-hour basis. Under the MM price-policy scenario, net benefits range between $69 million and $82 million. Under the LN price-policy

[68] Due to a minor error discovered in the original analysis, these results differ slightly from those in the September 2019 report.

scenario, the PVRR(d) benefits range between a $7 million benefit and a $1 million cost, depending upon the period used to extrapolate benefits beyond 2038. The execution of the Schedule 272 agreement with Vitesse was a necessary milestone to ensure the Pryor Mountain Wind Project could move forward and mitigates the risk of deteriorating value under a variety of price and policy scenarios, including the most conservative LN price policy scenario. Additionally, while not explicitly analyzed, customer benefits would increase significantly with high natural-gas price and/or high CO_2 price assumptions.

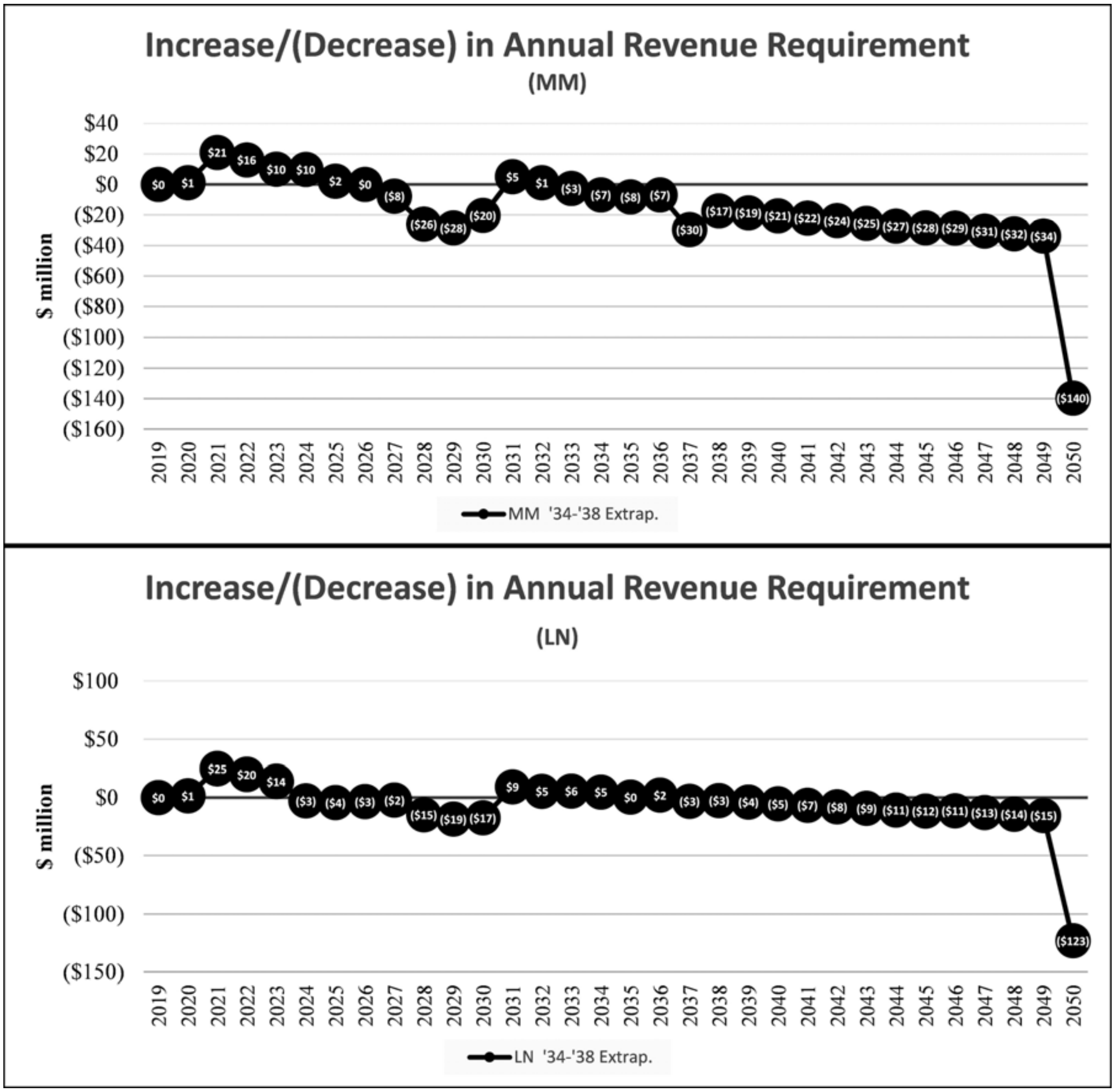
Table 11. Net Benefits from the Pryor Mountain Wind Project

Price-Policy Scenario (Extrapolation Method)	PVRR(d) Net (Benefit)/Cost ($ million)	Nom. Lev. Benefit ($/MWh of Incremental Energy)
MM ('28-'38 Extrapolation)	($69)	($7.22)
MM ('34-'38 Extrapolation)	($82)	($8.56)
LN ('28-'38 Extrapolation)	$1	$0.12
LN ('34-'38 Extrapolation)	($7)	($0.72)

Q. Have you analyzed the change in annual revenue requirement associated with the Pryor Mountain Wind Project?

A. Yes. Figure 8 shows the estimated change in nominal annual revenue requirement due to the Pryor Mountain Wind Project for the MM and LN price-policy scenarios with extrapolated benefits derived from modeled results over the period 2034-2038. This figure reflects the change in nominal revenue requirement associated with Pryor Mountain Wind Project netted against system benefits, which were calculated as described above. Considering both the MM and LN cases illustrated below, the Pryor Mountain Wind Project reduces nominal revenue requirement during a majority of its depreciable life.

Figure 8. (Reduction)/Increase in Total-System Annual Revenue Requirement from the Pryor Mountain Wind Project



VI. RESOURCE DECISIONS FOR COAL GENERATION UNITS

Q. Have you prepared economic analysis supporting major resource management decisions for coal generation units included in this case?

A. Yes. I present economic analysis supporting the conversion of Naughton Unit 3 to natural gas in 2020, the closure of Cholla Unit 4 in 2020, and the installation of SCR emissions control systems at Jim Bridger Units 3 and 4 in 2015-2016.

Naughton Unit 3 Natural Gas Conversion

Q. Please provide background on Naughton Unit 3.

A. The Naughton plant is located near Kemmerer, Wyoming. For several years PacifiCorp has been considering the conversion of Naughton Unit 3, a 280 MW resource, to a natural gas facility for environmental compliance purposes. The most recent permit from the Wyoming Air Quality Division requires Naughton Unit 3 to cease coal firing by January 30, 2019, and that gas conversion be completed by June 24, 2021.

Q. Did PacifiCorp end coal generation at Naughton Unit 3 in 2019?

A. Yes. Coal generation from Naughton Unit 3 ended on January 30, 2019.

Q. Does the 2019 IRP's preferred portfolio reflect the conversion of Naughton Unit 3 to a natural gas facility in 2020?

A. Yes. In the 2019 IRP preferred portfolio, Naughton Unit 3 is converted to natural gas in 2020, providing a low-cost reliable resource for meeting load and reliability requirements. The 2019 IRP action plan provides that PacifiCorp will complete the gas conversion of Naughton Unit 3, including completion of all required regulatory notices and filings, in 2020. The conversion will retrofit the unit to a natural gas fueled, slow start peaking unit at 75 percent maximum continuous rating, with expected generation of 247 MW. In his testimony, Mr. Teply describes the history and status of this conversion project, which is expected to be completed by mid-2020.

Q. In the 2019 IRP, how long does PacifiCorp assume Naughton Unit 3 will operate as a natural gas facility?

A. The 2019 IRP assumes Naughton 3 will operate as a natural gas facility through 2029.

Q. Does the conversion of Naughton 3 to natural gas benefit customers over other alternatives?

A. Yes. The cost of natural gas conversion is approximately $3 million, which equates to $12/kW. A new frame simple cycle combustion turbine located near the Naughton facility is estimated to cost $745/kW (2018 dollars). While the assumed design life of a new gas peaking asset is longer than the assumed life of Naughton Unit 3 once it is converted to a gas-fueled generating unit, the upfront capital required to convert natural gas is significantly less than the initial capital of new gas-fired generating unit. The gas conversion of Naughton Unit 3 represents an opportunity to maintain system capacity at a very low cost over a period in time where there are resource adequacy concerns in the region. PacifiCorp's analysis in the 2019 IRP demonstrates that, compared to early retirement of Naughton Unit 3, natural gas conversion has a PVRR(d) customer benefit ranging between $62 million and $121 million. The range of benefits is dependent upon the timing and magnitude of early coal unit retirement assumptions.

Q. Please explain the methods and assumptions used for the economic analysis in the 2019 IRP.

A. Informed by the 2019 IRP public-input process and results from coal studies that informed the 2019 IRP, initial portfolio development cases explored, among other things, alternative coal unit retirement assumptions. These cases also evaluated how system costs would be impacted if Naughton Unit 3 were converted to natural gas in 2020.

Case P-09 from the 2019 IRP is a variant of case P-03 that isolates the impact of converting Naughton Unit 3 to a 247 MW gas-fired facility in 2020. Both cases assume less accelerated coal retirements relative to the 2019 IRP preferred portfolio.[69] Through the end of 2024, the total coal capacity assumed to retire in cases P-09 and P-03 is 280 MW, which represents Naughton Unit 3 ending coal-fired operations in 2019. Through the end of 2027, the total coal capacity assumed to retire in cases P-09 and P-03 is 1,734 MW. The PVRR of system costs in case P-09, where Naughton Unit 3 is assumed to convert to a 247 MW gas-fired facility in 2020, is $62 million lower than in case P-03.

Similarly, Case P-10 from the 2019 IRP is a variant of case P-04 that isolates the impact of converting Naughton Unit 3 to a 247 MW gas-fired facility in 2020. Cases P-10 and P-04 assume more accelerated coal retirements relative to the 2019 IRP preferred portfolio. Through the end of 2024, the total coal capacity assumed to retire in cases P-10 and P-04 is 1,730 MW. Through the end of 2027, the total coal capacity assumed to retire in these cases is 2,568 MW. The PVRR of total system costs in case P-10, where Naughton Unit 3 is assumed to convert to a 247 MW gas-fired facility in 2020, is $121 million lower than P-04. As compared to the PVRR(d) between cases P-09 and P-03, customer benefits are higher with the increase in accelerated coal retirements assumed in cases P-10 and P-04.

As noted above, cases developed in the initial portfolio development phase of the 2019 IRP were developed on the basis of outcomes of modeled results and stakeholder feedback. Subsequent cases produced during the initial portfolio development phase of the 2019 IRP were designed to evaluate cost and risk impacts

[69] The 2019 IRP preferred portfolio assumes 1,018 MW and 2,441 MW of early coal unit retirements through the end of 2024 and 2027, respectively.

of other variables (*i.e.*, further analysis of coal unit retirement timing and price-policy assumptions). Based on the findings described above, subsequent cases produced in the 2019 IRP—including the case that was ultimately identified as the preferred portfolio—retained the assumption that Naughton Unit 3 is converted to a 247 MW gas-fired facility in 2020.

Retirement of Cholla Unit 4 in 2020

Q. Please provide background on PacifiCorp's Cholla Unit 4.

A. PacifiCorp owns 100 percent of Cholla Unit 4 which was commissioned in 1981 and has a generating capability of 395 MW. Arizona Public Service owns Cholla Units 1 and 3 (Unit 2 was retired in October 2015) and operates the entire Cholla facility. PacifiCorp owns approximately 37 percent of the plant's common facilities.

Q. For environmental compliance reasons, is PacifiCorp required to cease operations at Cholla Unit 4 or convert it to natural gas by April 30, 2025?

A. Yes.

Q. Does PacifiCorp's 2019 IRP preferred portfolio include early retirement of Cholla Unit 4?

A. Yes. PacifiCorp's 2019 IRP preferred portfolio reflects customer benefits associated with Cholla Unit 4's retirement as early as 2020. Given the unique ownership structure at the Cholla plant, PacifiCorp's action plan commits PacifiCorp to initiating the process of retiring Cholla Unit 4 and removing it from service no later than January 2023 and earlier if possible.

Q. Does PacifiCorp currently plan to retire Cholla 4 by year-end 2020?

A. Yes. PacifiCorp has initiated the process of retiring Unit 4 and anticipates being able to achieve retirement by year-end 2020, earlier than the January 2023 timeframe initially set forth in the 2019 IRP action plan

Q. Did PacifiCorp conduct additional economic analysis on the retirement of Cholla Unit 4 in 2020?

A. Yes. Further economic analysis building on the IRP studies confirm that early closure at the end of 2020 is expected to generate more present-value customer benefits relative to the plant continuing operation through April 2025.

Q. Please describe your economic analysis.

A. The economic analysis relies on an assessment of system value which compares the outcomes of the IRP's PaR scenarios with a simulation period covering the 2019-2025 timeframes. Consistent with the 2019 IRP preferred portfolio, the simulations use a range of natural gas price and carbon policy scenarios which incorporate a CO_2 price beginning in 2025 (medium natural gas price and medium CO_2 price assumptions (the "MM" price-policy scenario); low natural gas price and no CO_2 price assumptions (the "LN" price-policy scenario), and high natural gas price and no CO_2 price assumptions (the "HN" price-policy scenario)).[70]

Each price-policy scenario was run twice—one to update the 2019 preferred portfolio where Cholla Unit 4 is assumed to retire at the end of December 2020, and the other assuming Cholla Unit 4 continues operation through the April 2025 time frame. Each price-policy scenario showed an increase in net system costs when it

[70] For both PaR runs produced under the MM price-policy scenario, price assumptions were developed from PacifiCorp's September 2019 official forward price curve. LN and HN price-policy scenarios are derived from third-party sources. Natural gas prices in the LN price-policy scenario do not drop below prices in the MM scenario until 2026-beyond the early retirement study period. Consequently, the primary difference between the MM and LN price-policy scenario is the absence of a CO_2 price in 2025 in the LN scenario.

was assumed that Cholla Unit 4 operates as a coal-fired facility through April 30, 2025.

The updated economic analysis confirms PacifiCorp's ongoing IRP analyses and demonstrates that retirement of Unit 4 by year-end 2020 will produce net customer benefits relative to a case where Unit 4 continues operating through April 2025. This outcome is consistent across a range of price-policy scenarios. This holds true even with incremental costs, such as the closure-related costs, in part because PacifiCorp will no longer incur the operating costs associated with running Unit 4.

Q. Please provide the specific results of your economic analysis.

A. Early closure at the end of 2020 is expected to generate between $96 million and $123 million in present-value customer benefits relative to an alternative where the unit continues to operate through April 2025. All three price-policy scenarios report an increase in net system costs when it is assumed that Cholla Unit 4 operates as a coal-fired facility through April 30, 2025 relative to the case where it is assumed to retire at the end of 2020.

As shown in Table 12, the year-end 2020 retirement case under the MM price-policy scenario shows $121 million in present-value customer benefits. In the HN and LN price-policy scenarios, the year-end 2020 retirement case produce present-value customer benefits of $96 million and $123 million, respectively. In each price-policy scenario, the cost to replace system capacity and energy in the early retirement case are lower than the ongoing costs of maintaining operations through April 2025.

Table 12 - PVRR(d) Net (Benefit)/Cost of Year-End 2020 Retirement

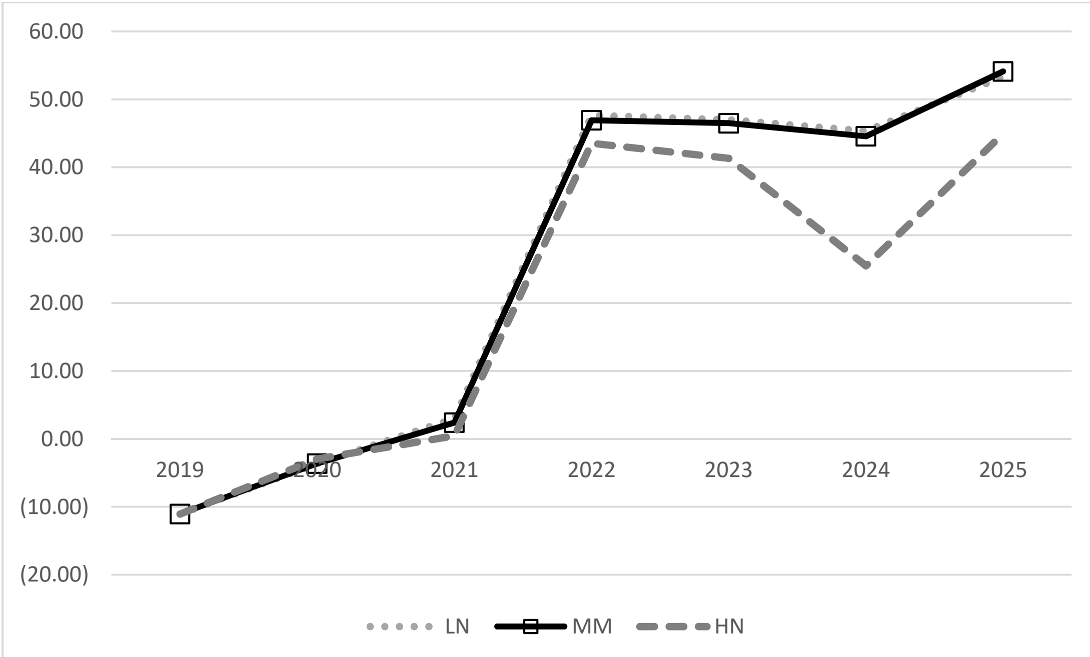
Price Policy Scenario	PVRR(d) Net (Benefit)/Cost of a Year-End 2020 Retirement ($ million)
Medium Gas, Medium CO_2	($121)
Low Gas, No CO_2	($123)
High Gas, No CO_2	($96)

Q. Please explain these results in more detail.

A. In each price-policy scenario, when Cholla Unit 4 operates through April 2025, fuel expenses (ranging from $53 million to $73 million on a present-value basis) and run-rate fixed costs ($122 million on a present-value basis) exceed the net value of system balancing market transactions (ranging from $28 million to $31 million on a present-value basis). While continued operation of Cholla Unit 4 through 2025 reduces the cost of liquidated damages associated with the coal supply-agreement, these savings do not offset the ongoing operating cost of the unit.

The customer benefits in the MM and LN price-policy scenarios are similar. Annual cost differences in the system simulation between these two scenarios are very small, and consequently, present-value customer benefits in both scenarios are nearly identical. In the HN price-policy scenario, the high price of natural gas leads to a modest increase in generation, and consequently, fuel costs, from Cholla Unit 4. However, the relative reduction in other system variable costs (i.e., fuel costs from other generators and system-balancing market transactions) is greater in the HN price-policy scenario, which reduces present-value customer benefits of the year-end 2020 early retirement case relative to the MM price-policy. Figure 9 illustrates the cost differentials for each price-policy scenario on an annual basis.

Figure 9 – Nominal Net System (Benefit)/Cost of Year-End 2020 Retirement ($ million)

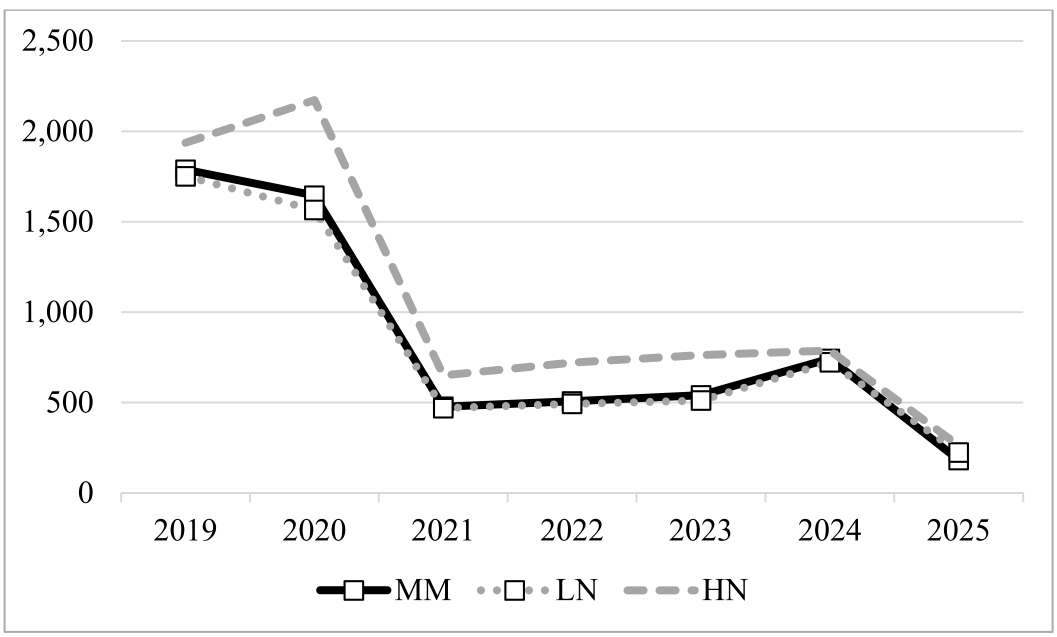


Q. Does the year-end 2020 early retirement of Cholla Unit 4 increase costs in 2020, followed by decreased costs between 2021-2025?

A. Yes. Increases in 2020 costs are primarily associated with an estimated $3.3 million of safe harbor lease early termination payments. PacifiCorp's acquisition of Cholla Unit 4 was subject to a pre-existing safe harbor lease, for federal income tax purposes, between Arizona Public Service (APS), as property owner, and General Electric Company as tax lessor. PacifiCorp assumed certain rights and obligations of APS under the safe harbor lease with respect to Cholla Unit 4. Under the early retirement case, a casualty payment is assumed to be paid to General Electric Company for its loss of tax benefits ($2.9 million cost on a present-value basis), and the amortization of pre-paid availability and transmission charges related to the Mead-Phoenix line. When PacifiCorp acquired Cholla Unit 4, the company paid APS a prepaid availability and transmission charge in April 1994 and April 1996. The charges are related to the construction of transmission facilities that enable an additional 150 MW of northbound firm transmission capability on the Phoenix-Mead transmission line. The prepaid transmission service cost began being amortized over a 50-year life in May 1997 as PacifiCorp began receiving transmission credits on its bill from APS. Under the early retirement case, it is assumed the unamortized balance would be written off, which is estimated to have an unamortized balance of $9.2 million in 2020 and $6.7 million in 2025 ($3.9 million cost on a present-value basis).

Beyond 2020, the 2020 year-end early retirement of Cholla Unit 4 reduces net system costs through the assumed April 2025 retirement date. Over this period, projected generation from Cholla Unit 4 declines, and the value of energy net of fuel costs is insufficient to offset annual fixed operating costs. Annual generation levels for Cholla Unit 4 are summarized in Figure 10.

Figure 10 – Cholla Generation by Price-Policy Scenario (GWh)



Jim Bridger Units 3 and 4 SCR Emissions Control Systems

Q. Has PacifiCorp included the costs of the SCR emissions control systems at Jim Bridger Units 3 and 4 in this case?

A. Yes. While the decision to invest in the SCR systems was made many years ago, this is the first GRC PacifiCorp has filed since these systems were installed.

Q. Please summarize your testimony on the Jim Bridger SCR emissions control systems.

A. PacifiCorp's economic analysis of SCR emission control systems at Jim Bridger Units 3 and 4 demonstrate that these systems were expected to provide net customer benefits relative to alternatives that included conversion to natural gas and early retirement. Specifically, my testimony on the SCR systems at Jim Bridger Units 3 and 4 presents the following:

- A description of the methodology used to analyze the SCR systems required to continue operating Jim Bridger Units 3 and 4 as coal-fueled facilities.
- A base case economic analysis showing $183 million in total company present-value customer benefits from the SCR systems that are necessary to continue operating Jim Bridger Units 3 and 4 as coal-fueled assets.
- Natural-gas price and CO_2 price scenario assumptions and results showing a range of economic outcomes that support the SCR systems in six of the nine scenarios studied.
- A description of an additional sensitivity showing that the Jim Bridger Units 3 and 4 SCR systems are favorable to both gas conversion and early retirement alternatives.

Q. Have circumstances changed since PacifiCorp made the decision to install SCR emission control systems at Jim Bridger Units 3 and 4?

A. Yes. PacifiCorp conducted its economic analysis as part of its 2013 IRP.[71]

[71] *See*, Docket No. LC 57, PacifiCorp's 2013 IRP Submittal (April 30, 2013).

PacifiCorp decided in May 2013 to move forward with SCR emission control systems for Jim Bridger Units 3 and 4 based on this analysis. This timeline was designed to comply with environmental regulations requiring action by the end of 2015 for Unit 3 and by the end of 2016 for Unit 4.[72]

Since then, PacifiCorp has continued to evaluate its coal fleet as part of the biennial IRP process as economic conditions have evolved. In PacifiCorp's 2019 IRP, the risk-adjusted, least-cost portfolio for the first time includes retirement of Jim Bridger Units 3 and 4 in 2037.[73] In addition, Oregon's laws governing resource emissions have changed and now prohibit coal generation in rates after 2030.

This information was not available to PacifiCorp at the time it made the decision to install SCRs, and prudence of this investment must be measured based on what was known at the time a decision was made, without reliance on hindsight. In the intervening years since the SCR emission control systems were installed (in late 2015 and late 2016 for Units 3 and 4, respectively),[74] customers have received and will continue to receive the benefits of this low-cost resource.

Q. Did the Commission decline to acknowledge the SCR emission control systems at Jim Bridger Units 3 and 4 in the 2013 IRP?

A. Yes. The Commission stated that it did not have enough information to resolve the issues brought up by other parties. Instead the Commission indicated that it would "undertake a thorough and fair review of the prudence of PacifiCorp's decision in a future rate case proceeding."[75] In my testimony and exhibits, I provide the

[72] PAC/800, Teply/26.
[73] Docket No. LC 70, PacifiCorp 2019 IRP, p.13.
[74] PAC/800, Teply/31.
[75] *In the Matter of PacifiCorp, dba Pacific Power*, LC 57, Order No. 14-252, at 19 (July 8, 2014).

information necessary to demonstrate that PacifiCorp was prudent in making this investment.

Methodology

Q. What model was used to evaluate the SCR emission control systems for Jim Bridger Units 3 and 4?

A. PacifiCorp used its SO model to perform a PVRR(d) economic analysis of the SCR emission control systems at Jim Bridger Units 3 and 4. This same analysis was presented in PacifiCorp's 2013 IRP and 2013 IRP Update, and in the Wyoming CPCN process for the SCR systems at Jim Bridger Units 3 and 4 described in the testimony of Mr. Teply.

Q. Is this the same SO model used to analyze the Energy Vision 2020 projects described above?

A. Yes.

Q. Why is the SO model an appropriate tool for analyzing incremental emission control equipment installations required on coal resources?

A. The SO model is the appropriate modeling tool when evaluating capital investment decisions and alternatives to those investments that might include early retirement and replacement or conversion of assets to natural gas. The SO model is capable of simultaneously and endogenously evaluating capacity and energy trade-offs between emission control systems required to meet environmental regulations and a broad range of alternatives, including fuel conversion, early retirement and replacement with greenfield resources, market purchases, demand-side management resources, and/or renewable resources. In this way, the SO model captures the cost implications of prospective emission control installation decisions by evaluating NPC impacts along with the impacts those decisions might have on future resource acquisition needs. This is particularly important when resource retirement and replacement is an environmental compliance alternative.

Q. How was the SO model used to analyze the PVRR(d) of the SCR systems required for Jim Bridger Units 3 and 4?

A. For a range of market price scenarios, which I describe later in my testimony, two SO model simulations were completed—an optimized simulation and a change-case simulation. In the optimized simulation, the SO model determined whether continued operation of Jim Bridger Units 3 and 4 inclusive of incremental SCR systems and other planned costs required to achieve compliance with environmental regulations was a lower cost solution than avoiding those expenses through early retirement and resource replacement or through conversion to natural gas. In the change-case simulation, the SO model was forced to produce a suboptimal decision by not allowing it to make the preferred decision that was made in the optimized simulation.

When the optimized simulation selected continued operations with incremental SCR emission control systems and other planned costs, then the change case was created by removing the SCR emission control systems as an alternative, allowing the SO model to select either an early retirement or gas-conversion alternative. In each of these change-case simulations, the SO model selected natural-gas conversion as a lower-cost alternative to early retirement. In scenarios where the optimized simulation selected conversion to natural gas, then the change case forced continued operations with incremental SCR emission control systems and other planned costs. The difference in total-company costs, inclusive of differences in NPC, operating costs and capital costs, between the two simulations for any given market-price scenario represents the PVRR(d), which establishes how favorable or unfavorable the incremental environmental capital investments planned for Jim Bridger Units 3 and 4 are in relation to the next best alternative.

Q. What incremental environmental investment costs were assumed for Jim Bridger Units 3 and 4?

A. Incremental environmental investment costs applied in the SO model include the cost of the SCR emission control systems required for Jim Bridger Units 3 and 4, along with projected costs required to achieve compliance with an array of known and emerging environmental regulations. This included costs to achieve compliance with the U.S. Environmental Protection Agency's mercury and air toxics standard, and costs to achieve compliance with prospective rules on coal-combustion residuals and cooling water intake structures. The incremental investment costs assumed in the SO model for Jim Bridger Units 3 and 4 along with other coal resources in PacifiCorp's fleet are summarized in Confidential Exhibit PAC/704.

Q. What resource-replacement alternatives were made available to the SO model in the event SCR emission control systems were not installed on Jim Bridger Units 3 and 4?

A. In addition to brownfield natural-gas conversion of Jim Bridger Units 3 and 4, the SO model was configured with a range of resource-replacement alternatives, which included:

- greenfield natural-gas resources;
- firm market purchases;

- demand-side management; and
- incremental wind resources.

Since the installation of SCR systems was required by December 31, 2015, for Jim Bridger Unit 3 and by December 31, 2016, for Jim Bridger Unit 4, resource retirement and replacement alternatives were assumed to be available beginning January 2016 and January 2017, respectively. Natural-gas conversion alternatives were made available beginning March 2016 for Jim Bridger Unit 3 and March 2017 for Jim Bridger Unit 4, assuming coal-fueled operation would continue as long as possible and the work to complete the gas conversion could be accomplished over a two-month period.

Q. Did PacifiCorp's economic analysis consider how the power requirements from the SCR emission control systems might affect the net capacity of Jim Bridger Units 3 and 4?

A. Yes. The SCR emission control systems, once installed and operational, were assumed to reduce PacifiCorp's share of capacity of both Jim Bridger Unit 3 and Unit 4 by approximately 3.5 MW.

Q. Did your analysis account for changes in the fueling plan at the Jim Bridger plant between the SCR and natural-gas conversion or early-retirement scenarios?

A. Yes. If Jim Bridger Units 3 and 4 were to convert to natural gas or retire early, the coal fueling needs at the four-unit Jim Bridger plant would be reduced, which in turn, would influence mine plans and reclamation plans. Cash coal cost assumptions used in the SO model were based on non-capital-related costs to fuel the Jim Bridger plant, which included then-current third party coal prices and transportation costs from

Black Butte coal as well as then-current cash operating cost forecasts for Bridger Coal Company (BCC) inclusive of final reclamation trust contributions. Under a two-unit coal operating plan, cash costs assumed closure of the Bridger Coal surface mine. Under a four-unit coal operating plan, cash costs assumed a two dragline operation at the surface mine. Cash coal cost assumptions for both the two-unit and four-unit coal operating plans used in the economic analysis are provided in Confidential Exhibit PAC/705.

Q. Please describe mine reclamation costs considered in PacifiCorp's economic analysis.

A. In 1989, the BCC owners established a final reclamation trust to fund actual final reclamation work. A sinking fund calculation is used to determine the appropriate final reclamation trust contribution rate and ensure sufficient funds exist in the trust to support final reclamation work once coal production ceases. Contributions to the final reclamation trust were included as part of the Jim Bridger plant cash coal costs through 2030, the study horizon used for the SO model analysis. Considering that reclamation costs continue beyond the 2030 study horizon, reclamation costs from 2031 through 2037 were included in the PVRR(d) calculations to capture differences in reclamation costs beyond the SO model study period. Confidential Exhibit PAC/706 summarizes reclamation costs for both the two-unit and four-unit coal operating plans used in the economic analysis.

Q. Did PacifiCorp consider differences in incremental mine capital costs between the two-unit and four-unit coal operating plans?

A. Yes. Over the period 2013 through 2030, average annual mine capital cost assumptions for a four-unit coal operating plan are higher than those in a two-unit coal operating plan. Confidential Exhibit PAC/707 shows annual mine capital cost assumptions used in the economic analysis for both the two-unit and four-unit coal operating plans.

Natural-Gas and CO_2 Price Scenarios

Q. Please explain why natural-gas and CO_2 price assumptions were important when analyzing the SCR emission control systems at Jim Bridger Units 3 and 4.

A. PacifiCorp evaluated early retirement and resource replacement or conversion of Jim Bridger Unit 3 and Unit 4 to natural gas as alternatives to SCR emission control systems. The assumed price for natural gas directly affects the cost for gas-fueled replacement resources in the case of an early retirement alternative or the fuel cost and replacement energy in the case of a gas conversion alternative. The price for natural gas is also a key factor in setting wholesale power prices. In this way, natural-gas prices disproportionately affect the value of energy net of operating costs from Jim Bridger Units 3 and 4 when operating as a coal-fueled resource versus the value of energy net of operating costs from a natural gas-fueled resource replacement alternative. Similarly, because of the relatively high level of carbon content in coal as compared to natural gas, higher CO_2 prices disproportionately affect the prospective cost of emissions between coal resources and natural gas as an alternative to the incremental investments required to continue operating Jim Bridger Units 3 and 4 as coal-fueled assets.

Q. Did PacifiCorp evaluate different assumptions for natural-gas prices and CO_2 prices in its analysis of the Jim Bridger Units 3 and 4 SCR systems?

A. Yes. PacifiCorp conducted a robust examination of alternative courses of action over a wide range of scenarios and input assumptions. In total, eight different combinations of natural-gas and CO_2 price assumptions were analyzed as variations to the base case, which was tied to the September 2012 OFPC. Table 13 summarizes the directional changes to base case assumptions among the eight scenarios. Two scenarios assume low and high natural-gas prices with base case CO_2 assumptions held constant; two scenarios assume low and high CO_2 price assumptions with the underlying base case natural-gas prices held constant; and four scenarios pair different combinations of natural-gas price and CO_2 price assumptions. In any scenario where the CO_2 assumption varies from that used in the base case, the underlying natural-gas price assumption was adjusted to account for an assumed natural-gas price response from changes in electric sector natural-gas demand.

Table 13. Natural-Gas and CO_2 Price Scenarios

Description	Natural-Gas Prices	CO_2 Prices
Base Case	September 2012 OFPC	\$16/ton in 2022 rising to \$23/ton by 2030
Low Gas, Base CO_2	Low	\$16/ton in 2022 rising to \$23/ton by 2030
High Gas, Base CO_2	High	\$16/ton in 2022 rising to \$23/ton by 2030
Base Gas, \$0 CO_2	Base case adjusted for price response	No CO_2 costs
Base Gas, High CO_2	Base case adjusted for price response	\$14/ton in 2020 rising to \$65/ton by 2030
Low Gas, High CO_2	Low case adjusted for price response	\$14/ton in 2020 rising to \$65/ton by 2030
High Gas, \$0 CO_2	High case adjusted for price response	No CO_2 costs
Low Gas, \$0 CO_2	Low case adjusted for price response	No CO_2 costs
High Gas, High CO_2	High case adjusted for price response	\$14/ton in 2020 rising to \$65/ton by 2030

Q. Why were natural-gas price assumptions adjusted in those scenarios where CO_2 price assumptions vary from the base case?

A. As I stated earlier, CO_2 prices disproportionately affect the prospective cost of emissions between coal resources and natural-gas alternatives. This is primarily driven by the relatively high level of carbon content in coal as compared to natural gas. With rising CO_2 prices, generating resources with lower CO_2 emissions, such as natural gas-fueled resources, can begin to displace coal-fueled generation, thereby increasing the demand for natural gas within the electric sector of the U.S. economy. Displacement of coal generation can also be influenced by low- or zero-emitting renewable generation sources; however, it was assumed that these low- or zero-emitting renewable resources would not entirely offset increased natural-gas demand. Conversely, with falling CO_2 prices (or a market that is absent CO_2 prices), there is no incremental emissions-based cost advantage for natural gas or renewable generation as compared to coal, and demand for natural gas in the electric sector of the U.S. economy could be slightly lower. It is assumed that any change in natural-gas demand must be balanced with a change in supply such that higher natural-gas demand yields an upward movement in price and lower natural-gas demand yields a downward movement in price.

Q. Did PacifiCorp only apply upward adjustments to natural-gas prices in response to changes in CO_2 price level?

A. No. The assumed interaction between natural-gas prices and CO_2 prices was applied on a bi-directional basis. That is, PacifiCorp not only assumed natural-gas prices rise in the presence of a CO_2 price (or with increased CO_2 price levels), but also incorporated downward natural-gas price pressures when CO_2 prices were removed or lowered.

Q. How did PacifiCorp choose its natural-gas and CO_2 price assumptions as used in the eight market price scenarios?

A. The range of low- and high-price assumptions were based upon the range of then current third-party expert forecasts and government agency price projections. Confidential Exhibit PAC/708 shows how the low and high price assumptions that were used in PacifiCorp's economic analysis compare to these third-party forecasts.

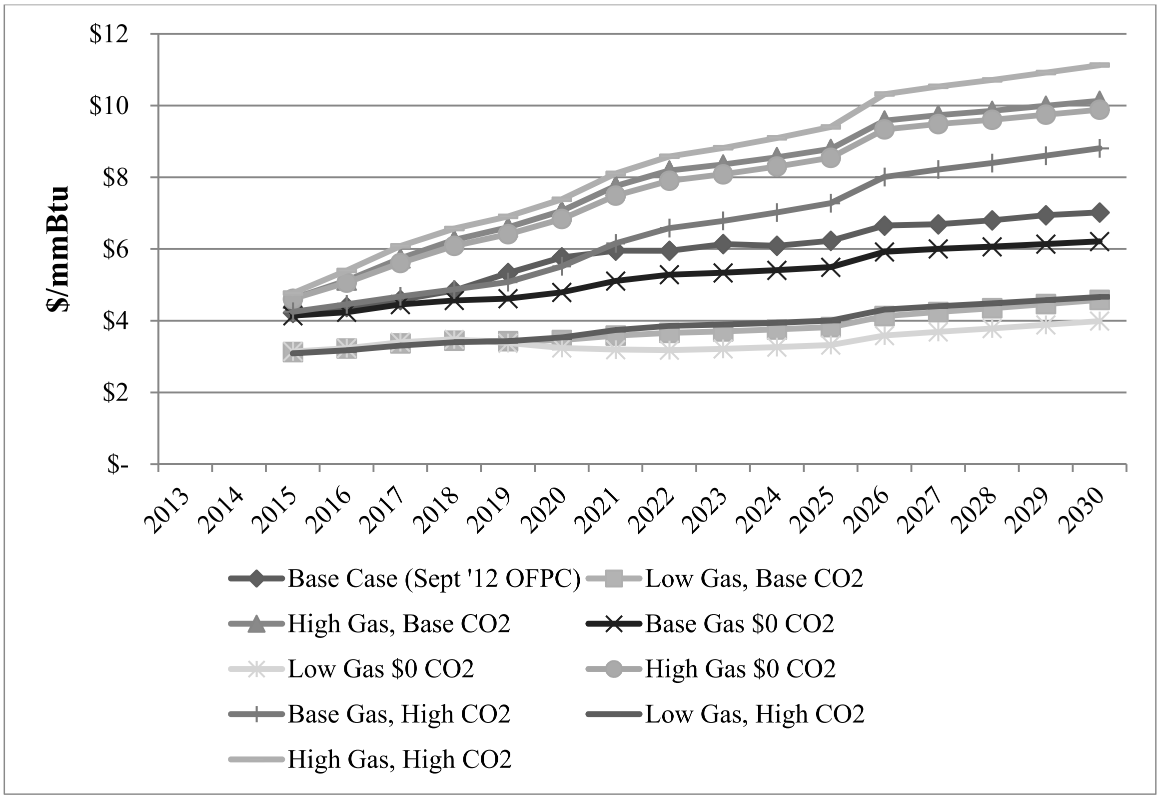
Low natural-gas price assumptions were derived from a third-party, low price scenario, which was characterized by strong and price-resilient shale gas supply growth and stagnant exports of liquefied natural gas out of the U.S. natural-gas market. The high natural-gas price assumptions were based on a blend of two, third-party price scenarios. This blending approach recognized that the most extreme high natural-gas price forecast was a strong outlier relative to price projections from other forecasters, and would have resulted in a high-price scenario that exceeds the highest of 47 natural-gas price forecasts in the U.S. Energy Information Administration's 2011 Annual Energy Outlook.[76]

Fundamental drivers to a high price scenario included constraints or disappointments in shale gas production, linkage to rising oil prices through substantial new demand in the transportation sector, and/or significant increases in liquefied natural-gas exports out of the U.S. natural-gas market. Figure 11 shows the

[76] The U.S. Energy Information Administration is the statistical and analytical agency within the U.S. Department of Energy. The highest natural-gas price forecast in the 2011 Annual Energy Outlook assumed that total unproved technically recoverable shale gas resources are reduced by 49 percent and that the estimated ultimate recovery per shale gas well is 50 percent lower than what was in their reference case.

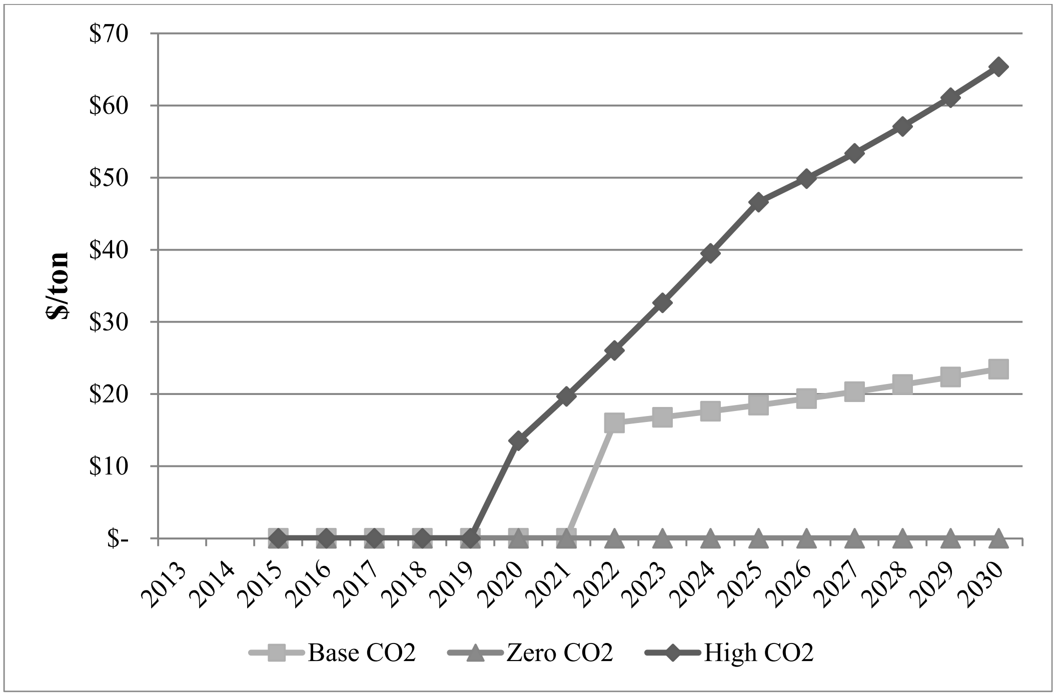
Henry Hub natural-gas price forecast among all market price scenarios considered in the economic analysis of the SCR emission control systems at Jim Bridger Units 3 and 4.

Figure 11. Henry Hub Natural-Gas Prices among All Scenarios



PacifiCorp assumed a zero CO_2 price for the low scenario, recognizing that there had been limited activity in the CO_2 policy arena. For the high CO_2 price scenario, prices were assumed to begin in 2020, escalate rapidly through 2025 and reach $65/ton by 2030. The high CO_2 price scenario aligns with the then-current high CO_2 price forecast from a third-party source. Figure 12 shows the three CO_2 price assumptions used in the market-price scenarios supporting the economic analysis.

Figure 12. CO_2 Prices among All Scenarios



Base-Case Results

Q. Please describe the base-case results.

A. The optimized base-case simulation selected the SCR emission control systems at Jim Bridger Unit 3 and Jim Bridger Unit 4. The change-case simulation in which Jim Bridger Units 3 and 4 were not allowed to select SCR emission control systems showed that gas conversion was the next best, albeit higher cost, alternative to the installation of these SCR systems. The PVRR(d), as summarized in Exhibit PAC/709, shows that installation of SCR systems is $183 million lower cost than gas conversion.

Q. How were system costs impacted between the base-case simulation, where SCRs were installed on Jim Bridger Units 3 and 4, and the change-case simulation, where both units were converted to natural gas?

A. When SCR emission control systems were installed on Jim Bridger Units 3 and 4, total-company fuel costs are lower and net system balancing revenues are higher relative to a natural-gas conversion alternative that would significantly reduce generation levels from the two units. These total-company benefits more than offset the increased fixed costs associated with the capital for the SCR emission control systems, which were assumed to be approximately $372/ kW higher than gas conversion capital costs, and levelized annual operating and run-rate capital costs, which were assumed to be approximately $52/kW higher than projected gas conversion costs. On a total-company basis, the PVRR(d) of system variable costs was $775 million favorable to the SCR systems compliance alternative, which more than offset the $592 million increase to total-company fixed costs.[77]

Natural-Gas and CO_2 Price Scenario Results

Q. Please describe the results from the natural-gas and CO_2 price scenarios.

A. The natural-gas and CO_2 price scenario results showed that the investment in SCR emission control systems at Jim Bridger Unit 3 and Jim Bridger Unit 4 remained favorable to the next best, albeit higher cost natural-gas conversion alternative under all base and high natural-gas price scenarios at all assumed CO_2 price levels. In these scenarios, the PVRR(d) ranges between $51 million favorable for the SCR systems (base gas, high CO_2) and $997 million favorable for the SCR systems (high gas, zero CO_2). The PVRR(d) results were unfavorable for the SCR systems only in those scenarios where then-current low natural-gas prices were assumed.

When low natural-gas price assumptions were paired with base CO_2 price

[77] System variable costs include fuel, net system balancing revenue, variable O&M expenses, and CO_2 emissions expenses, as applicable. System fixed costs include incremental environmental controls costs, fixed O&M and run-rate capital expenses for existing and new resources, and changes to system demand-side management costs.

assumptions, the nominal levelized price of natural gas at Opal[78] over the period 2016 to 2030 is \$3.70 per million British thermal units (MMBtu) and the PVRR(d) is \$285 million unfavorable for the SCR emission control systems required at Jim Bridger Units 3 and 4. In the low natural-gas, zero CO_2 price-policy scenario, the nominal levelized price of natural gas at Opal is \$3.41 per MMBtu over the 2016-to-2030 time frame, and the PVRR(d) is \$224 million unfavorable for the SCR emission control systems. When low natural-gas prices are paired with high CO_2 price assumptions, the nominal levelized price at Opal over the period 2016 to 2030 is \$3.78 per MMBtu, and the PVRR(d) is \$378 million unfavorable for the SCR emission control systems. The PVRR(d) results from the natural-gas and CO_2 price scenarios are summarized alongside the base case results in Exhibit PAC/709.

Q. How did the PVRR(d) results trend among the different updated natural-gas price assumptions?

A. The scenario results show that there is a strong trend between natural-gas price assumptions and the PVRR(d) benefit/cost associated with the SCRs required for continued operation of Jim Bridger Units 3 and 4 as coal-fueled assets. With higher natural-gas price assumptions, the SCR emission control systems are more favorable as compared to the Jim Bridger Unit 3 and Unit 4 gas conversion alternative. Conversely, lower natural-gas prices improve the PVRR(d) results in favor of the gas conversion alternative. Lower natural-gas prices reduce the fuel cost of the gas conversion alternative, reduce the fuel cost of the other natural gas-fueled system resources that partially offset the generation lost from the coal-fueled Jim Bridger

[78] Opal is a natural-gas market hub located in Lincoln County, Wyoming.

units, and reduce the opportunity cost of reduced off-system sales when Jim Bridger Units 3 and 4 operate as a gas-fueled generation assets.

Q. Could you infer from this trend how far natural-gas prices would have had to fall for gas conversion to have been favorable to installation of SCR systems at Jim Bridger Units 3 and 4?

A. Yes. Confidential Exhibit PAC/710 graphically displays the relationship between the nominal levelized natural-gas price at Opal over the period 2016 through 2030 and the PVRR(d) benefit/cost of continued coal operation of Jim Bridger Units 3 and 4 with installation of SCR emission control systems. To isolate the effects of CO_2 prices, which as I described earlier were assumed to elicit a natural-gas price response due to changes in demand for natural gas in the electric sector, the natural-gas price relationship with PVRR(d) results is shown for the natural-gas price scenarios in which the base case CO_2 price assumption was used. Based on this trend, levelized natural-gas prices over the period 2016 through 2030 would have to decrease by 15 percent, from $5.72 per MMBtu to $4.86 per MMBtu, to achieve a breakeven PVRR(d). This is referred to as the "breakeven analysis" for changes in natural-gas prices.

Q. How did the PVRR(d) results trend among the different CO_2 price assumptions?

A. Higher CO_2 price assumptions improve the PVRR(d) in favor of the gas conversion alternative, and lower CO_2 prices improve the economics of the SCR emission control systems. As with the trend described in the relationship between natural-gas prices and the PVRR(d) results, the relationship between CO_2 prices and the PVRR(d) benefit/cost of the SCR systems required at Jim Bridger Units 3 and 4 is intuitive.

Because the CO_2 content of coal is nearly double the CO_2 content of natural gas, higher CO_2 prices lead to relatively lower cost of emissions for the gas conversion alternative and offset the costs related to any generation lost from the coal-fueled Jim Bridger Units 3 and 4 assets.

Q. What CO_2 price would be required to change the PVRR(d) results in favor of converting Jim Bridger Units 3 and 4 to natural gas?

A. Confidential Exhibit PAC/711 includes a graphical representation of the relationship between the nominal levelized CO_2 price over the period 2016 to 2030 and the PVRR(d) benefit/cost of installing the SCR emission control systems. To isolate the effects of fundamental shifts in the natural-gas price assumptions, the CO_2 price relationship with the PVRR(d) results is shown for the two CO_2 price scenarios that were paired with the same underlying base case natural-gas price assumption. Based upon the trend between PVRR(d) and nominal levelized CO_2 price assumptions, the levelized CO_2 prices over the period 2016 through 2030 would need to exceed $30 per ton, more than three times the base case nominal levelized CO_2 price assumption, to achieve a breakeven PVRR(d) for the Jim Bridger Unit 3 and Unit 4 SCR emission control systems.

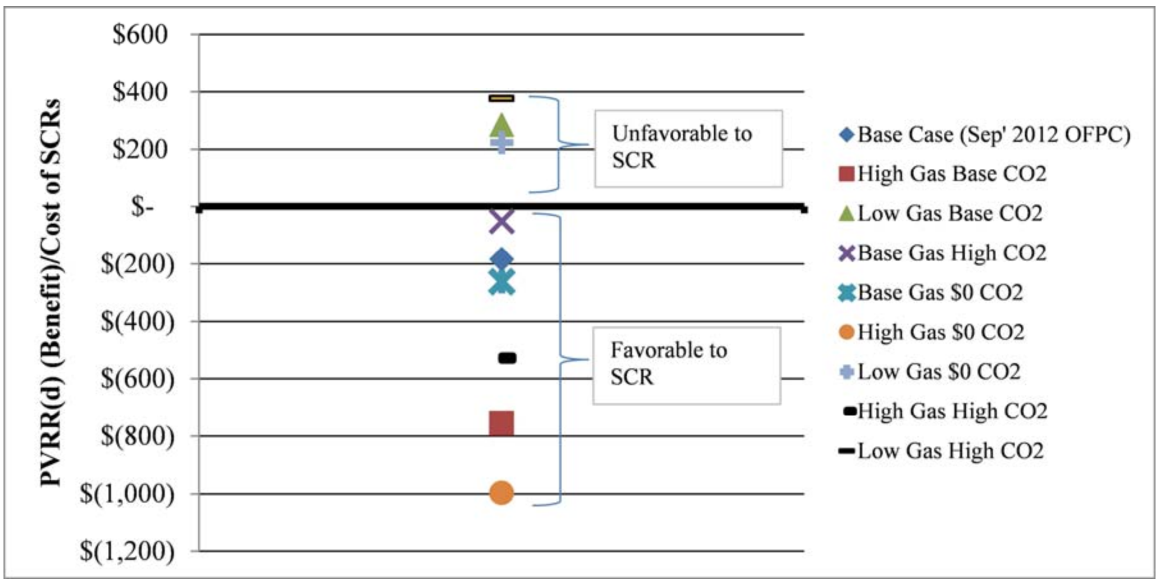
Q. How did PacifiCorp use the natural-gas and CO_2 price scenario results to inform its decision to install the Jim Bridger Unit 3 and Unit 4 SCR emission control systems?

A. PacifiCorp first reviewed the magnitude of the PVRR(d) results from the base case, which is defined by assumptions representing the Company's best estimate of forward-looking assumptions at the time the analysis was completed. The base-case results provided an initial look at how favorable or unfavorable the SCR systems are in relation to the next best alternative and provided context when reviewing scenario results. The base case results summarized earlier in my testimony yield a PVRR(d) showing that the Jim Bridger Unit 3 and Unit 4 SCR systems would be $183 million lower cost than the natural-gas conversion alternative. This outcome also shows that when PacifiCorp's best estimate of forward-looking assumptions were used, there was a reasonably sized "cushion" in the PVRR(d) results allowing for some erosion of the favorable economics should long-term natural-gas prices or CO_2 prices change from what was assumed in the base case analysis. The natural-gas and CO_2 price scenarios were then used to quantify how sensitive the PVRR(d) results are to these key assumptions and provided a foundation for judging risk.

Q. Can you describe how PacifiCorp evaluated risk in the context of the results from the natural-gas and CO_2 price scenarios?

A. Yes. Figure 13 shows the distribution of PVRR(d) results for the base case and the eight natural-gas and CO_2 price scenarios. The figure shows that of the nine cases analyzed, six scenarios produce a PVRR(d) favorable to the SCR systems and the three scenarios with low gas price assumptions produce a PVRR(d) that was unfavorable to the SCR systems. The figure further illustrates the range of potential PVRR(d) outcomes among the scenarios analyzed. At one end of the spectrum, the PVRR(d) for the high gas, zero CO_2 scenario is $997 million favorable to the SCR systems. On the other end of the spectrum, the PVRR(d) for the low gas high CO_2 scenario is $378 million unfavorable to the Jim Bridger Unit 3 and Unit 4 SCR systems. Among the scenarios analyzed, the distribution of PVRR(d) outcomes indicate a disproportionate risk profile. While there is a possibility that the evolution of future natural-gas prices could have rendered the decision to invest in SCR systems to be higher cost than a gas conversion alternative, the cost impacts to customers of such an outcome were projected to be higher under a gas conversion alternative should future natural-gas prices rise relative to the base case.

Figure 13. Distribution of Scenario PVRR(d) Results

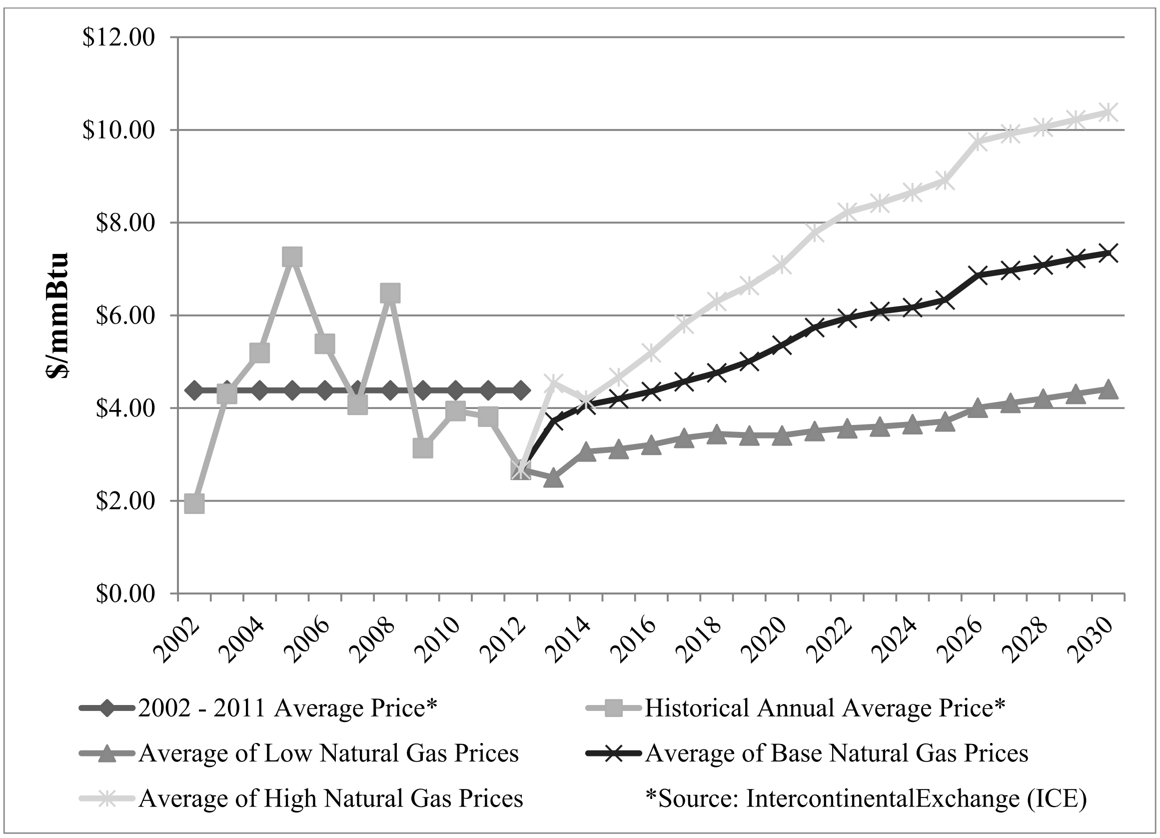


Q. Given the impact of low gas prices on the PVRR(d) results, how did you analyze the uncertainty around future natural-gas prices?

A. I compared the potential range of future natural-gas price scenarios in the context of historical natural-gas price levels. Figure 14 plots historical natural-gas prices alongside the average annual natural-gas price at Opal among the three low natural-gas price scenarios, the three base natural-gas price scenarios, and the three high natural-gas price scenarios.

Opal natural-gas prices in the low natural-gas price scenarios never reach 2002 to 2012 historical average prices over the course of the next 18 years. Among the low natural-gas price scenarios, the average annual price for natural gas at Opal over the period 2013 through 2030 is $3.59 per MMBtu, which is 18 percent below 2002–2012 historical price levels. Among the base natural-gas price scenarios, which are representative of the best estimate of forward-looking assumptions available at the time, the average annual price for Opal natural gas was $5.66 per MMBtu, or 29 percent above 2002–2012 historical price levels. Among the high natural-gas price scenarios, Opal natural-gas prices averaged $7.60 per MMBtu, representing a 73-percent increase relative to 2002-2012 historical prices.

Figure 14. Average Annual Natural-Gas Prices at Opal



Q. Did PacifiCorp consider the impact of changing market conditions on its Jim Bridger SCR analysis before issuing a full notice to proceed (FNTP) in December 2013?

A. Yes. As discussed above, the Company produced natural-gas price sensitivities that show a strong linear relationship between natural-gas price inputs and the PVRR(d) between the SCR and natural-gas-conversion compliance alternatives, which is displayed in Confidential Exhibit PAC/710. Given the significance of this relationship, PacifiCorp developed the breakeven analysis to allow for rapid re-assessment of the PVRR(d) between the SCR and natural-gas conversion compliance alternatives. This analytical tool allowed the Company to monitor changing market conditions affecting the financial viability of the investment at significant project milestones without having to recreate the more time-intensive economic analysis to account for changes in forward gas prices. The breakeven analysis specifically complemented flexibility provisions negotiated in the EPC contract, which is described further in Mr. Teply's testimony. PacifiCorp used this breakeven analysis before selecting installation of SCR emission control systems as the best compliance alternative in May 2013. Between May and December 2013, management personnel were in frequent contact and regularly monitoring the economics of the SCR investment. Before issuing the FNTP on December 1, 2013, PacifiCorp once again evaluated natural-gas prices relative to the breakeven price point to assess how changes in market conditions affected customer benefits.

Q. What were forward natural-gas prices at the time PacifiCorp committed to installing SCR systems at Jim Bridger Units 3 and 4?

A. PacifiCorp's economic analysis of the Jim Bridger SCRs used base-case natural-gas prices from the Company's September 2012 OFPC, which yielded a nominal levelized price at Opal over the 2016-through-2030 time frame of $5.72 per mmBtu. Before issuing the FNTP on December 1, 2013, PacifiCorp reviewed the most recent OFPC from September 2013, which yielded a nominal levelized price at Opal of $5.35 per mmBtu over the 2016-through-2030 time frame. This was well above the break-even levelized Opal natural-gas price for the SCRs at $4.86/mmBtu. Based upon the breakeven relationship described above, PacifiCorp determined that the SCR emission control systems remained the most economical environmental compliance option for Jim Bridger Units 3 and 4, benefiting customers by approximately $130 million more than the gas-conversion alternative.[79]

When evaluating natural-gas prices before issuing the FNTP, PacifiCorp also considered that there is uncertainty in long-term natural-gas price forecasts, that natural-gas prices cannot trend downward indefinitely, and that there was a reasonable possibility that actual natural-gas prices could be higher than then-current base-case projections.

[79] Furthermore, after September 2013, there were no indications that prices had fallen below the breakeven point. In late October 2013, PacifiCorp received price forecasts from third-party consultants indicating no major changes from their prior forecasts. In fact, two of PacifiCorp's three third-party forecasts increased after September 2013. And the only consultant forecast that was less than the break-even point showed a decline of less than one percent relative to the same consultant's August forecast. Although the company does not make long-term resource decisions based on isolated forecasts and short-term market forwards, these data demonstrated it was reasonable to continue to rely on the September 2013 OFPC.

Q. Please explain how PacifiCorp considered the impact of reduced EPC contract costs on the SCR benefits before issuing the FNTP.

A. Before issuing the FNTP PacifiCorp was aware that EPC costs for the Jim Bridger SCR emission control systems had been reduced by [redacted]. The reduced EPC cost contributes approximately [redacted] in additional benefits to the SCR compliance alternative. These incremental benefits, tied to fixed costs for the SCR systems, are easily calculated, and no model runs are required to understand how reduced EPC costs improve benefits for the SCR compliance alternative. Before issuing the FNTP, PacifiCorp knew that these EPC cost reductions would only add to the already substantial benefits of the SCR compliance alternative even after accounting for reduced base-case natural-gas price assumptions. Moreover there would have been increased costs and risks of natural-gas conversion under a hypothetical post-FNTP cancellation.

Q. Based on all the analysis described above, was it in customers' best interest to pursue the installation of SCR emission control systems at Jim Bridger Units 3 and 4?

A. Yes. The economic analysis conducted by PacifiCorp clearly showed that installation of the SCR emission control systems was the least-cost, least-risk alternative. While some changes to inputs and assumptions occurred during this period, there were no red flags that indicated that the substantial SCR benefits had eroded or that natural gas conversion had become the more economical compliance alternative.

Early Retirement Sensitivity Analysis

Q. Did PacifiCorp's base case and scenario analyses allow for early retirement as an alternative to the SCR emission control systems?

A. Yes. PacifiCorp conducted a sensitivity analysis of early retirement, one of the alternatives to the SCR emission control systems, as part of its in-depth evaluation to stress test the viability of this investment. The PVRR(d) was calculated by taking the difference in system costs between two SO model simulations. One simulation assumed the SCR emission control systems would be installed and Jim Bridger Unit 3 and Unit 4 would continue operating as coal-fueled assets. The second simulation forced Jim Bridger Unit 3 and Unit 4 to stop operating as coal-fueled assets, allowing the model to choose among the most economical alternative, which includes gas conversion and early retirement. In all the simulations forcing Jim Bridger Unit 3 and Unit 4 to stop operating as coal-fueled assets, the SO model chose gas conversion over early retirement when it is was assumed that the SCR emission control systems would not be installed.

Q. Did PacifiCorp perform an additional sensitivity that showed gas conversion would be a lower cost alternative to the SCR emission control systems than an early-retirement alternative?

A. Yes. For this sensitivity, in the case where Jim Bridger Unit 3 and Unit 4 were assumed to stop operating as coal-fueled assets, each unit was forced to retire (not allowing it to choose gas conversion) for purposes of calculating the PVRR(d).

Q. What are the results of this sensitivity analysis?

A. When Jim Bridger Unit 3 and Unit 4 were forced to retire early, the SO model added a 597 MW combined-cycle unit located in southern Utah in 2017.[80] As compared to an early retirement alternative, the PVRR(d) is $588 million in favor of the Jim Bridger Unit 3 and Unit 4 SCR emission control systems. The sensitivity also shows that gas conversion, while unfavorable to the SCR systems, has a PVRR(d) that is $405 million favorable to early retirement.

VII. SALES AND LOAD FORECAST

Q. Please summarize your testimony on PacifiCorp's sales and load forecast.

A. I provide PacifiCorp's forecasts of the number of customers, kWh sales at the meter (sales), system loads and system peak loads at the system input level (loads), and number of bills by rate schedule for the 12-month period ending December 31, 2021. PacifiCorp's load forecast has been updated with the most recent information available and includes certain changes in methodology to more accurately forecast load.

Q. When did PacifiCorp prepare the sales and load forecast used in this filing?

A. PacifiCorp completed the sales and load forecast used in this filing in June 2019. This is PacifiCorp's most recent forecast of sales and loads.

Q. How did PacifiCorp use the June 2019 sales and load forecast in this filing and in the concurrent 2021 Transition Adjustment Mechanism (2021 TAM) filing?

A. Ms. Shelley E. McCoy used the sales and load forecast to calculate inter-jurisdictional allocation factors. The sales forecast by rate schedule was used by Mr. Robert M. Meredith to allocate costs between customer classes and to design rates that correctly

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[80] Incremental front office transactions are also included in the portfolio when Jim Bridger Unit 3 and 4 are forced to retire early.

reflect the cost of service. The load forecast was also used by Mr. Webb to calculate net power costs in the 2021 TAM filing.

Q. Have there been any updates to the forecast methodology since the forecast prepared for PacifiCorp's last Oregon rate case, docket UE 263 (2013 Rate Case), and the 2014 TAM, docket UE 264?

A. Yes. As discussed below, PacifiCorp updated its commercial sales model, residential customer model, transportation electrification, and the street lighting sales model.

Q. Please provide a general overview of PacifiCorp's sales and load forecast methodology.

A. PacifiCorp first develops a forecast of monthly sales by customer class and monthly peak load by state. This sales forecast becomes the basis of the load forecast by adding line losses, meaning kWh sales levels are grossed-up to a generation or "input" level. The monthly loads are then spread to each hour based on the peak load forecast and typical hourly load patterns to produce the hourly load forecast.

Q. Please provide a summary of the forecasted energy sales for 2021.

A. Table 14 provides the forecasted energy sales for the 12-month period ending December 31, 2021.

Table 14 – Test Period Sales Forecast (MWh)

	2020 GRC (CY 2021)	
	Total Company	**Oregon**
Residential	**16,314,413**	**5,671,134**
Commercial	**19,256,803**	**5,996,343**
Industrial	**19,176,292**	**1,682,735**
Irrigation	**1,469,416**	**333,381**
Lighting	**99,688**	**32,935**
Total	**56,316,612**	**13,716,528**

Comparisons to Past Sales Forecasts

Q. How does the total-company sales forecast for 2021 compare to the sales forecast used in the 2013 Rate Case?

A. As shown in Table 15, total-company 2021 forecast sales are 2.9 percent higher than 2014 forecast sales used in the 2013 Rate Case. The difference in the forecasts is attributable to an increase in commercial, residential and irrigation load. The growth in the commercial class is related to data centers and reclassification of public authority sales as commercial sales. The industrial class decrease in the forecast is attributable to a decline in commodity prices over the 2014-to-2015 time frame.

Table 15 – Total Company Sales Comparison (MWh)

	Previous GRC CY 2014	Current GRC CY 2021	Percentage Change
Residential	15,912,619	16,314,413	2.5%
Commercial	17,321,091	19,256,803	11.2%
Industrial	19,825,363	19,176,292	-3.3%
Irrigation	1,245,400	1,469,416	18.0%
Public Authority	276,500	-	-100.0%
Lighting	141,650	99,688	-29.6%
Total	54,722,623	56,316,612	2.9%

Q. How does the Oregon sales forecast for 2021 compare to the sales forecast used in the 2013 GRC?

A. As shown in Table 16, the 2021 Oregon sales forecast has increased by approximately 4.2 percent from the 2014 sales forecast used in the 2013 Rate Case. On an Oregon basis, the commercial class increase reflects the continuing expansion of data centers in Oregon. The increase in residential class sales is driven by customer growth offset by a decline in use-per-customer. The decline in the industrial load reflects the loss of a large Oregon industrial customer.

Table 16 - Oregon Sales Comparison (MWh)

	Previous GRC CY 2014	Current GRC CY 2021	Percentage Change
Residential	**5,381,873**	**5,671,134**	**5.4%**
Commercial	**5,378,807**	**5,996,343**	**11.5%**
Industrial	**2,133,140**	**1,682,735**	**-21.1%**
Irrigation	**238,210**	**333,381**	**40.0%**
Lighting	**36,940**	**32,935**	**-10.8%**
Total	**13,168,971**	**13,716,528**	**4.2%**

Forecast Methodology

Q. Please summarize major updates used to produce the 2021 forecast as compared to the forecast used in the 2013 Rate Case.

A. PacifiCorp updated many of its data inputs and assumptions using the most recent information available, including updates to the historical data periods for sales, monthly forecasts, line losses, normal weather, and temperature splines; market drivers; customer usage; and the residential use-per-customer model with appliance saturation and efficiency results.

Q. Please describe the changes in the load forecast methodology since the 2013 Rate Case.

A. To increase accuracy, PacifiCorp changed the commercial forecast methodology from a use-per-customer model to a total usage model, similar to that used for the industrial class forecast. This update was first incorporated into the load forecast used for the 2015 TAM in docket UE 287.

PacifiCorp also updated its residential customer forecasting methodology by adopting a differenced model approach in the development of the forecast of residential customers. Rather than directly forecasting the number of customers, the differenced model predicts the monthly change in number of customers, which produces a more accurate customer forecast. This methodology update was first incorporated into the load forecast used for the 2020 TAM forecast in docket UE 356.

There are two updates new to this filing. First, PacifiCorp developed a transportation electrification projection based on current and expected electric-vehicle adoption trends. This projection was incorporated as a post-model adjustment to the residential and commercial sales forecasts. Second, PacifiCorp incorporated a light emitting diode (LED) lighting adoption curve for its street lighting forecast. The adoption curve was developed to predict how the conversion to this more efficient technology is impacting sales.

Monthly Sales Forecast Methodology

Q. How are the forecasts for number of customers developed?

A. For the residential class, PacifiCorp forecasts the number of customers using IHS Markit's forecast of number of households or population as the major driver. For the commercial class, PacifiCorp forecasts the number of customers using the forecasted number of residential customers as the major economic driver. For the industrial, irrigation and street lighting classes, the customer forecasts are fairly static and developed using time series or regression models without any economic drivers.

Q. What methodology does PacifiCorp use to forecast the residential class sales?

A. PacifiCorp develops the residential sales forecasts as a product of two separate forecasts: (1) the number of customers—as described above; and (2) sales per customer. PacifiCorp models sales-per-customer for the residential class through a Statistically Adjusted End-Use model, which combines the end-use modeling concepts with traditional regression analysis techniques.

Q. What methodology does the Company use to forecast the commercial class sales?

A. For the commercial class, PacifiCorp forecasts sales using regression analysis techniques with non-manufacturing employment or non-farm employment, as the economic drivers, in addition to weather-related variables. Also, similar to how the PacifiCorp forecasts its largest industrial customers, data center forecasts are based on input from the Company's regional business managers (RBMs).

Q. How does PacifiCorp forecast sales for the industrial customer class?

A. The majority of industrial customers are modeled using regression analysis with trend and economic variables. Manufacturing employment is used as the major economic driver. For a small number of industrial customers (the largest customers on the system), PacifiCorp individually prepares forecasts based on input from the customer and the RBMs.

Q. What methodology does PacifiCorp use for the irrigation and lighting sales forecasts?

A. For the irrigation class, PacifiCorp forecasts sales using regression analysis techniques based on historical sales volumes and weather-related variables. Monthly sales for lighting are forecast using regression analysis techniques based on historical sales volumes and a LED lighting adoption curve.

Hourly Load Forecast

Q. Please outline how the hourly load forecast is developed.

A. After PacifiCorp develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps. First, monthly peak forecasts are developed for each state. The monthly peak model uses historical peak-producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. This forecast is based on average monthly historical peak-producing weather for the 20-year period 1999 through 2018.

Second, hourly load forecasts are developed for each state using hourly load models that include state-specific hourly load data, daily weather variables, the 20-year average temperatures identified above, a typical annual weather pattern, and day-type variables such as weekends and holidays as inputs to the model. The hourly loads are adjusted to match the monthly peaks from the first step above. Also, the hourly loads are adjusted so the monthly sum of hourly loads equals monthly sales plus line losses.

Q. How are monthly system coincident peaks derived?

A. After the hourly load forecasts are developed for each state, hourly loads are aggregated to the total system level. The system coincident peaks can then be identified, as well as the contribution of each jurisdiction to those monthly peaks.

Forecasts by Rate Schedule

Q. Were any additional forecasts created for these proceedings?

A. Yes. As mentioned earlier, Mr. Meredith requires two additional forecasts that are based on the kWh sales forecast and the number of customers forecast. Once the kWh sales forecast is complete, it must be applied to individual rate schedules to forecast kWh sales by rate schedule. In addition, the forecast of number of customers by rate schedule must be expressed in number of bills.

Q. How are rate schedule level forecasts produced?

A. PacifiCorp develops this forecast in two steps: (1) it forecasts test year sales by rate schedule; and (2) it proportionally adjusts the rate schedule sales forecasts so that the total matches the customer class forecast.

Q. Finally, how does PacifiCorp forecast the number of bills for each rate schedule?

A. The forecast of the number of bills for each rate schedule follows the same process as the sales forecast for each rate schedule. First, PacifiCorp forecasts the number of bills by class and by rate schedule. Then, PacifiCorp proportionally adjusts the forecasted number of bills by rate schedule so that the total number of bills matches the customer class forecasted number of bills.

VIII. CONCLUSION

Q. Based on your testimony, what do you recommend to the Commission?

A. I recommend that the Commission conclude that PacifiCorp's EV 2020 Wind Projects and Transmission Projects, Foote Creek I repowered wind facility and the Pryor Mountain Wind Project are reasonable and prudent. I also recommend that the Commission approve the costs of the major resource management decisions PacifiCorp has made with respect to its coal generation units.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 374
Exhibit PAC/701
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Rick T. Link

Nominal Henry Hub Natural Gas Price Forecasts

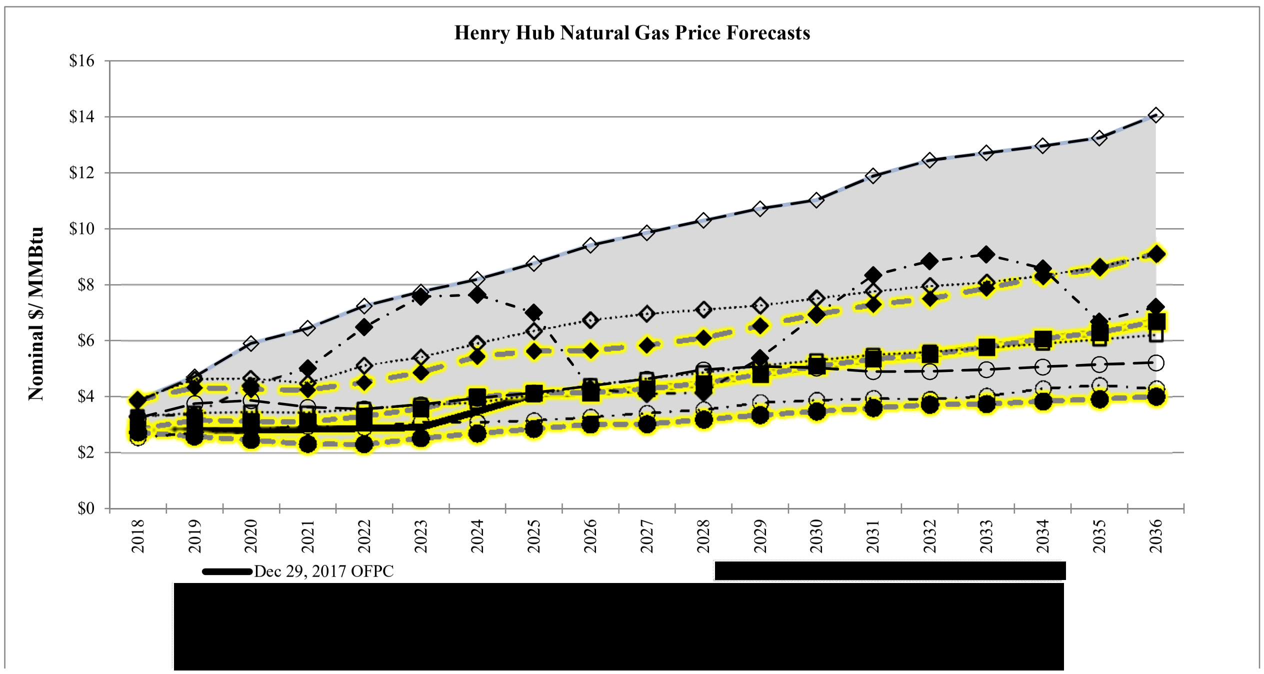
February 2020

REDACTED

Confidential Exhibit No. PAC/701

Nominal Henry Hub Natural Gas Price Forecasts ($/MMBtu)

Year	Dec 29, 2017 OFPC	[redacted]									Lowest Price	Highest Price	Range
2018	$2.85	$2.85	$3.89	$2.74	$3.31	$3.89	$3.31	$3.24	$3.83	$2.56	$2.56	$3.89	$1.33
2019	$2.81	$3.18	$4.33	$2.60	$3.43	$4.63	$3.39	$3.75	$4.71	$2.73	$2.60	$4.71	$2.10
2020	$2.82	$3.13	$4.26	$2.47	$3.46	$4.65	$4.39	$3.86	$5.90	$2.87	$2.47	$5.90	$3.43
2021	$2.85	$3.12	$4.25	$2.33	$3.44	$4.49	$5.01	$3.62	$6.44	$2.97	$2.33	$6.44	$4.11
2022	$2.89	$3.31	$4.51	$2.32	$3.57	$5.12	$6.48	$3.56	$7.24	$2.92	$2.32	$7.24	$4.92
2023	$2.93	$3.58	$4.88	$2.54	$3.71	$5.42	$7.57	$3.71	$7.74	$3.11	$2.54	$7.74	$5.20
2024	$3.49	$4.00	$5.45	$2.71	$3.80	$5.91	$7.64	$3.94	$8.19	$3.11	$2.71	$8.19	$5.48
2025	$4.09	$4.14	$5.64	$2.87	$4.07	$6.35	$7.00	$4.14	$8.76	$3.16	$2.87	$8.76	$5.89
2026	$4.15	$4.15	$5.65	$3.03	$4.41	$6.74	$4.29	$4.37	$9.41	$3.28	$3.03	$9.41	$6.38
2027	$4.29	$4.29	$5.85	$3.04	$4.64	$6.97	$4.10	$4.63	$9.86	$3.43	$3.04	$9.86	$6.82
2028	$4.49	$4.49	$6.11	$3.20	$4.87	$7.12	$4.15	$4.96	$10.30	$3.55	$3.20	$10.30	$7.09
2029	$4.80	$4.80	$6.54	$3.36	$5.11	$7.26	$5.37	$5.08	$10.72	$3.80	$3.36	$10.72	$7.36
2030	$5.10	$5.10	$6.95	$3.49	$5.31	$7.52	$6.94	$5.03	$11.02	$3.88	$3.49	$11.02	$7.53
2031	$5.35	$5.35	$7.29	$3.61	$5.50	$7.77	$8.34	$4.89	$11.89	$3.95	$3.61	$11.89	$8.28
2032	$5.51	$5.51	$7.51	$3.72	$5.60	$7.95	$8.84	$4.90	$12.45	$3.92	$3.72	$12.45	$8.73
2033	$5.79	$5.79	$7.88	$3.75	$5.76	$8.08	$9.08	$4.97	$12.71	$4.03	$3.75	$12.71	$8.96
2034	$6.08	$6.08	$8.28	$3.84	$5.90	$8.33	$8.58	$5.07	$12.96	$4.29	$3.84	$12.96	$9.12
2035	$6.30	$6.30	$8.58	$3.93	$6.05	$8.64	$6.68	$5.15	$13.24	$4.41	$3.93	$13.24	$9.32
2036	$6.70	$6.70	$9.12	$4.01	$6.21	$9.10	$7.21	$5.21	$14.06	$4.29	$4.01	$14.06	$10.05



Docket No. UE 374
Exhibit PAC/702
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Rick T. Link

Combined Projects System Optimizer and Planning and Risk PVRR(d) (Benefit)/Cost, February 2018

February 2020

Exhibit No. PAC/702

SO Model Annual Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($857)	($0)	$0	$1	($13)	($99)	($100)	($103)	($102)	($106)	($106)	($109)	($122)	($122)	($136)	($132)	($132)	($144)	($158)	($138)	($136)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($92)	$0	($0)	($1)	($3)	($4)	($5)	($6)	($9)	($11)	($12)	($14)	($15)	($15)	($15)	($15)	($16)	($17)	($19)	($23)	($25)
Change in System Fixed Cost	($100)	$0	$0	$0	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($19)	($19)	($19)	($35)	($22)	($11)	($55)	($57)
Net (Benefit)/Cost	($185)	($0)	($0)	($0)	($15)	($46)	($44)	($49)	($51)	($52)	($54)	($54)	($69)	($76)	($61)	$74	$63	$69	$69	$47	$51

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($838)	($0)	($0)	$1	($13)	($99)	($100)	($104)	($103)	($107)	($107)	($110)	($124)	($124)	($137)	($126)	($126)	($129)	($130)	($129)	($113)
Change in Emissions	($40)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($17)	($21)	($19)	($19)	($17)	($25)
Change in DSM	($84)	$0	$0	($1)	($3)	($3)	($4)	($5)	($7)	($9)	($10)	($12)	($12)	($14)	($14)	($16)	($18)	($20)	($21)	($21)	($22)
Change in System Fixed Cost	($109)	$0	($0)	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($19)	($19)	($19)	($13)	($26)	($64)	($49)	($63)
Net (Benefit)/Cost	($208)	($0)	$0	($0)	($15)	($45)	($43)	($49)	($51)	($52)	($53)	($53)	($68)	($76)	($70)	$63	$68	$57	$23	$48	$47

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($909)	($0)	$1	$1	($13)	($100)	($101)	($104)	($104)	($109)	($111)	($119)	($143)	($151)	($152)	($138)	($136)	($156)	($157)	($156)	($143)
Change in Emissions	($145)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($11)	($20)	($17)	($22)	($37)	($55)	($60)	($45)	($42)	($49)	($63)
Change in DSM	($69)	$0	($2)	($2)	($3)	($3)	($4)	($6)	($7)	($7)	($8)	($8)	($9)	($10)	($11)	($12)	($13)	($14)	($15)	($16)	($16)
Change in System Fixed Cost	($110)	$0	$0	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($21)	($21)	($21)	($21)	($21)	($57)	($55)	($56)
Net (Benefit)/Cost	($370)	($0)	($1)	($1)	($15)	($45)	($44)	($49)	($51)	($51)	($66)	($78)	($102)	($124)	($112)	$15	$16	$16	($15)	($12)	($10)

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($1,060)	($0)	$1	$2	($13)	($104)	($107)	($109)	($112)	($125)	($124)	($128)	($143)	($159)	($178)	($195)	($196)	($204)	($230)	($208)	($173)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($68)	$0	($2)	($3)	($3)	($4)	($5)	($7)	($7)	($7)	($8)	($8)	($10)	($10)	($11)	($11)	($12)	($12)	($12)	($12)	($13)
Change in System Fixed Cost	($113)	$0	$0	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($21)	($21)	($21)	($19)	($24)	($7)	($63)	($115)
Net (Benefit)/Cost	($377)	($0)	($1)	($1)	($15)	($51)	($51)	($55)	($60)	($67)	($68)	($68)	($85)	($110)	($100)	$14	$19	$12	$7	($20)	($33)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($989)	($0)	$0	$1	($14)	($105)	($109)	($111)	($116)	($128)	($126)	($130)	($145)	($161)	($183)	($203)	($204)	($199)	($203)	($81)	($1)
Change in Emissions	($12)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($7)	($4)	($5)	($7)	($8)	($5)	($2)
Change in DSM	($48)	$0	($0)	($1)	($2)	($2)	($3)	($3)	($4)	($4)	($5)	($7)	($8)	($9)	($9)	($10)	($10)	($10)	($10)	($10)	($10)
Change in System Fixed Cost	($219)	$0	$0	$0	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($22)	($22)	($22)	($22)	($39)	($45)	($202)	($299)
Net (Benefit)/Cost	($405)	($0)	($0)	($0)	($15)	($50)	($51)	($54)	($60)	($67)	($67)	($68)	($85)	($111)	($111)	$2	$5	($3)	($9)	($35)	($45)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($910)	($0)	$0	$1	($14)	($94)	($97)	($99)	($103)	($113)	($111)	($122)	($126)	($125)	($172)	($193)	($207)	($86)	($90)	($171)	($177)
Change in Emissions	($103)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($14)	($18)	($37)	($50)	($32)	($14)	($21)	($22)	($23)	($21)	($23)
Change in DSM	($53)	$0	($1)	($1)	($2)	($3)	($3)	($4)	($4)	($5)	($7)	($7)	($8)	($9)	($11)	($11)	($11)	($11)	($11)	($11)	($11)
Change in System Fixed Cost	($287)	$0	$0	$0	($0)	($19)	($19)	($20)	($24)	($24)	($25)	($25)	($26)	($38)	($38)	($39)	($21)	($147)	($148)	($73)	($76)
Net (Benefit)/Cost	($489)	($0)	($0)	($0)	($15)	($55)	($55)	($58)	($64)	($71)	($85)	($96)	($122)	($142)	($143)	($15)	($13)	($14)	($14)	($13)	($19)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($1,213)	($0)	$0	$1	($21)	($127)	($137)	($130)	($141)	($149)	($149)	($154)	($172)	($188)	($204)	($180)	($125)	($214)	($189)	($279)	($264)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($48)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($6)	($6)	($6)	($6)	($8)	($8)	($8)	($8)	($9)	($9)	($10)	($10)	($11)
Change in System Fixed Cost	($303)	$0	$0	($0)	($0)	($3)	($3)	($27)	($30)	($31)	($32)	($32)	($33)	($41)	($55)	($92)	($147)	($57)	($99)	($41)	($67)
Net (Benefit)/Cost	($699)	($0)	($0)	($0)	($22)	($72)	($78)	($96)	($110)	($115)	($116)	($117)	($138)	($157)	($158)	($39)	($35)	($29)	($40)	($68)	($73)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($1,130)	($0)	$0	$1	($21)	($127)	($137)	($114)	($118)	($130)	($130)	($134)	($150)	($163)	($181)	($128)	($142)	($206)	($198)	($289)	($305)
Change in Emissions	($15)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($5)	($4)	($5)	($7)	($8)	($10)	($12)
Change in DSM	($51)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($6)	($6)	($6)	($7)	($8)	($8)	($9)	($9)	($10)	($10)	($11)	($12)	($12)
Change in System Fixed Cost	($383)	$0	$0	($0)	($0)	($3)	($3)	($48)	($52)	($53)	($54)	($55)	($56)	($63)	($76)	($138)	($129)	($62)	($83)	($27)	($25)
Net (Benefit)/Cost	($716)	($0)	($0)	($0)	($22)	($72)	($78)	($100)	($110)	($117)	($119)	($120)	($139)	($155)	($160)	($39)	($39)	($34)	($43)	($76)	($86)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($1,131)	($0)	$0	$1	($22)	($125)	($134)	($84)	($87)	($96)	($96)	($99)	($113)	($145)	($177)	($225)	($243)	($224)	($260)	($337)	($348)
Change in Emissions	($67)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($4)	($8)	($11)	($16)	($15)	($8)	($24)	($22)	($29)	($30)	($31)
Change in DSM	($41)	$0	($1)	($1)	($1)	($1)	($1)	($3)	($4)	($5)	($5)	($5)	($6)	($7)	($7)	($7)	($8)	($8)	($9)	($10)	($11)
Change in System Fixed Cost	($406)	$0	$0	($0)	($0)	($7)	($7)	($84)	($89)	($91)	($93)	($95)	($97)	($77)	($74)	($44)	($23)	($49)	($41)	$17	$13
Net (Benefit)/Cost	($781)	($0)	($0)	($0)	($22)	($73)	($78)	($107)	($114)	($120)	($127)	($131)	($151)	($165)	($163)	($44)	($52)	($52)	($82)	($97)	($109)

PaR Stochastic-Mean Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($757)	$0	$0	$1	($12)	($89)	($90)	($92)	($90)	($94)	($92)	($92)	($105)	($109)	($116)	($119)	($121)	($127)	($137)	($124)	($121)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($18)	$0	$0	$0	($0)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($3)	($2)	($2)	($2)	($2)	($3)	($4)	($3)	($3)
Change in DSM	($108)	$0	($1)	($2)	($3)	($5)	($6)	($8)	($10)	($13)	($15)	($16)	($17)	($18)	($18)	($18)	($18)	($19)	($20)	($25)	($27)
Change in Deficiency	($8)	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($3)	($4)	($3)	($2)	($6)	($2)	($4)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($100)	$0	$0	$0	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($19)	($19)	($19)	($35)	($22)	($11)	($55)	($57)
Net (Benefit)/Cost	($150)	$0	($0)	($1)	($15)	($41)	($39)	($44)	($47)	($48)	($49)	($45)	($60)	($72)	($53)	$74	$63	$76	$75	$50	$52

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($756)	$0	$0	$1	($13)	($90)	($90)	($93)	($92)	($96)	($94)	($94)	($107)	($111)	($118)	($120)	($121)	($121)	($119)	($119)	($110)
Change in Emissions	($36)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12)	($14)	($16)	($17)	($19)	($17)	($19)
Change in VOM	($17)	$0	$0	$0	($0)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($3)	($2)	($2)
Change in DSM	($93)	$0	$0	($1)	($3)	($4)	($5)	($6)	($8)	($10)	($12)	($13)	($13)	($15)	($16)	($18)	($20)	($21)	($22)	($22)	($24)
Change in Deficiency	($7)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($3)	($3)	($4)	($2)	($7)	($1)	($4)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($109)	$0	($0)	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($19)	($19)	($19)	($13)	($26)	($64)	($49)	($63)
Net (Benefit)/Cost	($179)	$0	($0)	($1)	($15)	($41)	($39)	($44)	($46)	($47)	($47)	($44)	($58)	($71)	($65)	$62	$66	$58	$19	$48	$43

Exhibit No. PAC/702

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($807)	$0	$1	$1	($13)	($90)	($90)	($93)	($92)	($97)	($99)	($102)	($120)	($125)	($131)	($133)	($133)	($134)	($131)	($136)	($137)
Change in Emissions	($159)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($11)	($22)	($30)	($37)	($46)	($48)	($51)	($52)	($54)	($52)	($52)
Change in VOM	($16)	$0	$0	$0	($0)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($3)
Change in DSM	($76)	$0	($2)	($3)	($3)	($3)	($5)	($7)	($7)	($7)	($8)	($9)	($10)	($11)	($12)	($13)	($14)	($16)	($16)	($17)	($18)
Change in Deficiency	($8)	$0	($0)	$0	$0	($0)	$0	$0	$0	$0	$0	$0	$0	($1)	($4)	($4)	($3)	($4)	($5)	($2)	($5)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($110)	$0	$0	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($21)	($21)	($21)	($21)	($21)	($57)	($55)	($56)
Net (Benefit)/Cost	($337)	$0	($1)	($1)	($15)	($41)	($39)	($44)	($45)	($45)	($60)	($69)	($97)	($119)	($111)	$17	$18	$19	($13)	($6)	($6)

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($941)	$0	$1	$2	($12)	($94)	($96)	($97)	($101)	($114)	($112)	($114)	($133)	($143)	($156)	($166)	($169)	($178)	($200)	($184)	($149)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($23)	$0	$0	$0	($0)	($2)	($3)	($3)	($3)	($3)	($3)	($3)	($2)	($3)	($3)	($3)	($3)	($5)	($6)	($4)	($4)
Change in DSM	($76)	$0	($2)	($3)	($4)	($4)	($6)	($7)	($8)	($8)	($9)	($9)	($11)	($11)	($12)	($12)	($13)	($13)	($13)	($13)	($15)
Change in Deficiency	($6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($4)	($5)	($1)	($5)	($1)	($4)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($113)	$0	$0	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($21)	($21)	($21)	($19)	($24)	($7)	($63)	($115)
Net (Benefit)/Cost	($319)	$0	($1)	($1)	($16)	($46)	($45)	($49)	($55)	($63)	($63)	($61)	($81)	($101)	($88)	$31	$34	$26	$23	($6)	($22)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($882)	$0	$0	$1	($13)	($95)	($97)	($99)	($104)	($117)	($114)	($115)	($135)	($144)	($162)	($171)	($175)	($176)	($177)	($74)	($3)
Change in Emissions	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($8)	($9)	($10)	($11)	($5)	($2)
Change in VOM	($21)	$0	$0	$0	($0)	($2)	($3)	($3)	($3)	($3)	($3)	($3)	($2)	($3)	($3)	($3)	($3)	($4)	($5)	($2)	($1)
Change in DSM	($53)	$0	($1)	($1)	($2)	($2)	($4)	($4)	($4)	($5)	($6)	($7)	($9)	($9)	($9)	($11)	($11)	($11)	($11)	($11)	($11)
Change in Deficiency	($4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($2)	($3)	($5)	$1	($2)	($1)	($0)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($219)	$0	$0	$0	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($22)	($22)	($22)	($22)	($39)	($45)	($202)	($299)
Net (Benefit)/Cost	($357)	$0	($0)	($1)	($15)	($45)	($45)	($47)	($55)	($63)	($62)	($60)	($81)	($102)	($101)	$19	$17	$10	$3	($36)	($52)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($804)	$0	$0	$1	($13)	($85)	($86)	($88)	($92)	($104)	($101)	($101)	($119)	($129)	($144)	($154)	($169)	($80)	($82)	($147)	($148)
Change in Emissions	($116)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($10)	($20)	($29)	($35)	($38)	($36)	($42)	($21)	($22)	($32)	($34)
Change in VOM	($17)	$0	$0	$0	($0)	($2)	($2)	($2)	($3)	($3)	($3)	($3)	($2)	($2)	($2)	($2)	($3)	($1)	($2)	($2)	($3)
Change in DSM	($57)	$0	($1)	($1)	($2)	($3)	($4)	($4)	($4)	($6)	($7)	($7)	($9)	($10)	($11)	($12)	($12)	($11)	($11)	($12)	($12)
Change in Deficiency	($7)	$0	$0	($0)	$0	$0	($0)	$0	$0	$0	$1	$0	$0	($1)	($2)	($2)	($2)	($3)	($3)	($4)	($9)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($287)	$0	$0	$0	($0)	($19)	($19)	($20)	($24)	($24)	($25)	($25)	($26)	($38)	($38)	($39)	($21)	($147)	($148)	($73)	($76)
Net (Benefit)/Cost	($448)	$0	($0)	($1)	($15)	($51)	($50)	($53)	($59)	($68)	($76)	($84)	($113)	($137)	($130)	($7)	($5)	($16)	($16)	($12)	($19)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($1,021)	$0	$0	$1	($19)	($115)	($122)	($113)	($118)	($123)	($122)	($122)	($143)	($159)	($173)	($154)	($109)	($176)	($152)	($227)	($214)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($19)	$0	$0	$0	($0)	($3)	($3)	($3)	($2)	($2)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($4)	($4)
Change in DSM	($52)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($6)	($7)	($7)	($7)	($8)	($9)	($9)	($9)	($10)	($10)	($10)	($11)	($11)
Change in Deficiency	($13)	$0	$0	$0	$0	$1	$0	$0	$1	$0	$0	$0	$1	($0)	($2)	($4)	($3)	($14)	($20)	($2)	($5)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($303)	$0	$0	($0)	($0)	($3)	($3)	($27)	($30)	($31)	($32)	($32)	($33)	($41)	($55)	($92)	($147)	($57)	($99)	($41)	($67)
Net (Benefit)/Cost	($568)	$0	($0)	($1)	($20)	($65)	($68)	($85)	($93)	($95)	($94)	($92)	($114)	($134)	($135)	($23)	($28)	($12)	($30)	($26)	($36)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($954)	$0	$0	$1	($19)	($115)	($122)	($99)	($101)	($107)	($105)	($106)	($125)	($138)	($153)	($110)	($120)	($171)	($165)	($237)	($249)
Change in Emissions	($21)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6)	($4)	($6)	($10)	($10)	($14)	($17)
Change in VOM	($18)	$0	$0	$0	($0)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($4)	($4)
Change in DSM	($55)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($6)	($7)	($7)	($8)	($9)	($9)	($10)	($10)	($10)	($11)	($12)	($13)	($14)
Change in Deficiency	($13)	$0	$0	$0	$0	$1	$0	$0	$1	$0	$0	$0	$1	$0	($1)	($3)	($2)	($15)	($19)	($3)	($5)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($383)	$0	$0	($0)	($0)	($3)	($3)	($48)	($52)	($53)	($54)	($55)	($56)	($63)	($76)	($138)	($129)	($62)	($83)	($27)	($25)
Net (Benefit)/Cost	($603)	$0	($0)	($1)	($20)	($65)	($68)	($91)	($97)	($100)	($100)	($98)	($119)	($135)	($142)	($30)	($26)	($23)	($38)	($38)	($50)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($955)	$0	$0	$1	($19)	($112)	($119)	($75)	($75)	($79)	($77)	($76)	($93)	($121)	($151)	($208)	($202)	($183)	($211)	($275)	($279)
Change in Emissions	($101)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($7)	($14)	($18)	($23)	($23)	($17)	($34)	($35)	($40)	($43)	($44)
Change in VOM	($19)	$0	$0	$0	($0)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($4)	($4)	($3)	($4)	($5)	($5)
Change in DSM	($44)	$0	($1)	($1)	($1)	($1)	($1)	($4)	($5)	($5)	($5)	($6)	($7)	($7)	($7)	($8)	($8)	($9)	($10)	($10)	($12)
Change in Deficiency	($9)	$0	$0	$0	$0	$1	$0	($0)	$1	$0	($0)	($0)	$0	$0	($0)	($2)	($2)	($16)	($4)	($3)	($7)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($406)	$0	$0	($0)	($0)	($7)	($7)	($84)	($89)	($91)	($93)	($95)	($97)	($77)	($74)	($44)	($23)	($49)	($41)	$17	$13
Net (Benefit)/Cost	($694)	$0	($0)	($1)	($20)	($66)	($68)	($103)	($107)	($109)	($116)	($120)	($143)	($153)	($152)	($46)	($30)	($47)	($56)	($59)	($70)

Docket No. UE 374
Exhibit PAC/703
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Rick T. Link

Combined Projects Nominal Revenue Requirement PVRR(d) (Benefit)/Cost, February 2018

February 2020

Exhibit No. PAC/703

Exhibit PAC/703
Link/1

Estimated Annual Revenue Requirement Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)	$0
System Impacts																																			
NPC	($1,069)	$0	$0	$1	($12)	($89)	($90)	($92)	($90)	($94)	($92)	($92)	($105)	($109)	($116)	($119)	($121)	($127)	($137)	($124)	($121)	($133)	($136)	($139)	($143)	($121)	($124)	($127)	($130)	($133)	($136)	($139)	($142)	($145)	($148)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($198)	$0	($1)	($2)	($3)	($7)	($8)	($10)	($13)	($15)	($18)	($19)	($20)	($21)	($23)	($25)	($24)	($24)	($30)	($30)	($34)	($28)	($28)	($29)	($30)	($25)	($26)	($27)	($27)	($28)	($28)	($29)	($30)	($30)	($31)
System Fixed Costs	($166)	$0	$0	$0	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($19)	($19)	($19)	($35)	($22)	($11)	($55)	($57)	($28)	($29)	($29)	($30)	($26)	($26)	($27)	($28)	($28)	($29)	($29)	($30)	($31)	($31)
Net System Impacts	($1,432)	$0	($0)	($1)	($16)	($99)	($101)	($106)	($110)	($116)	($116)	($118)	($132)	($149)	($159)	($163)	($180)	($172)	($178)	($209)	($212)	($189)	($194)	($198)	($203)	($173)	($176)	($180)	($185)	($188)	($193)	($197)	($202)	($206)	($210)
Net (Benefit)/Cost	$184	$0	($0)	($1)	$6	$71	$54	$33	$16	$4	($7)	($12)	($35)	($55)	($43)	$78	$59	$65	$56	$24	$20	$41	$36	$31	$25	$43	$39	$36	$32	$30	$28	$29	$32	$28	($455)

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																			
NPC	($1,061)	$0	$0	$1	($13)	($90)	($90)	($93)	($92)	($96)	($94)	($94)	($107)	($111)	($118)	($120)	($121)	($121)	($119)	($119)	($110)	($130)	($133)	($136)	($140)	($119)	($122)	($124)	($128)	($130)	($133)	($136)	($139)	($142)	($145)
Emissions	($66)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12)	($14)	($16)	($17)	($19)	($17)	($19)	($13)	($13)	($13)	($14)	($12)	($12)	($12)	($13)	($13)	($13)	($13)	($14)	($14)	($14)
Other Variable Costs	($178)	$0	$0	($1)	($3)	($6)	($7)	($8)	($11)	($12)	($14)	($15)	($15)	($18)	($21)	($23)	($26)	($25)	($32)	($26)	($30)	($26)	($27)	($27)	($28)	($24)	($24)	($25)	($25)	($26)	($27)	($27)	($28)	($28)	($29)
System Fixed Costs	($183)	$0	($0)	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($19)	($19)	($19)	($13)	($26)	($64)	($49)	($63)	($32)	($32)	($33)	($34)	($29)	($29)	($30)	($31)	($31)	($32)	($33)	($34)	($34)	($35)
Net System Impacts	($1,488)	$0	($0)	($1)	($16)	($98)	($100)	($105)	($109)	($115)	($115)	($116)	($130)	($148)	($171)	($176)	($176)	($190)	($234)	($211)	($222)	($201)	($206)	($210)	($215)	($183)	($187)	($191)	($196)	($200)	($204)	($209)	($215)	($218)	($223)
Net (Benefit)/Cost	$127	$0	($0)	($1)	$6	$71	$54	$34	$17	$5	($6)	($10)	($33)	($54)	($55)	$66	$63	$47	$0	$22	$10	$29	$24	$18	$13	$32	$28	$24	$20	$18	$16	$16	$20	$16	($468)

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																			
NPC	($1,149)	$0	$1	$1	($13)	($90)	($90)	($93)	($92)	($97)	($99)	($102)	($120)	($125)	($131)	($133)	($133)	($134)	($131)	($136)	($137)	($147)	($150)	($153)	($157)	($134)	($137)	($140)	($143)	($146)	($149)	($152)	($156)	($159)	($163)
Emissions	($279)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($11)	($22)	($30)	($37)	($46)	($48)	($51)	($52)	($54)	($52)	($52)	($51)	($52)	($54)	($55)	($47)	($48)	($49)	($50)	($51)	($52)	($53)	($55)	($56)	($57)
Other Variable Costs	($149)	$0	($2)	($3)	($3)	($5)	($7)	($9)	($10)	($10)	($11)	($11)	($12)	($14)	($18)	($19)	($19)	($22)	($24)	($21)	($25)	($21)	($22)	($22)	($23)	($19)	($20)	($20)	($21)	($21)	($21)	($22)	($22)	($23)	($23)
System Fixed Costs	($185)	$0	$0	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($21)	($21)	($21)	($21)	($21)	($57)	($55)	($56)	($32)	($33)	($33)	($34)	($29)	($30)	($30)	($31)	($32)	($33)	($33)	($34)	($35)	($36)
Net System Impacts	($1,762)	$0	($1)	($1)	($16)	($98)	($100)	($106)	($109)	($114)	($128)	($141)	($168)	($197)	($217)	($221)	($224)	($229)	($267)	($264)	($271)	($251)	($256)	($262)	($269)	($229)	($234)	($239)	($245)	($250)	($255)	($261)	($268)	($272)	($279)
Net (Benefit)/Cost	($147)	$0	($1)	($1)	$6	$71	$54	$33	$18	$6	($18)	($35)	($72)	($103)	($101)	$21	$15	$8	($32)	($32)	($39)	($21)	($27)	($34)	($41)	($13)	($18)	($23)	($29)	($31)	($34)	($35)	($33)	($38)	($523)

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																			
NPC	($1,366)	$0	$1	$2	($12)	($94)	($96)	($97)	($101)	($114)	($112)	($114)	($133)	($143)	($156)	($166)	($169)	($178)	($200)	($184)	($149)	($182)	($186)	($190)	($195)	($166)	($169)	($173)	($178)	($181)	($185)	($189)	($194)	($198)	($202)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($152)	$0	($2)	($3)	($4)	($6)	($8)	($10)	($11)	($11)	($12)	($12)	($13)	($15)	($17)	($19)	($21)	($19)	($24)	($18)	($22)	($20)	($21)	($21)	($22)	($19)	($19)	($19)	($20)	($20)	($21)	($21)	($22)	($22)	($23)
System Fixed Costs	($190)	$0	$0	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($21)	($21)	($21)	($19)	($24)	($7)	($63)	($115)	($33)	($34)	($34)	($35)	($30)	($31)	($31)	($32)	($33)	($33)	($34)	($35)	($36)	($37)
Net System Impacts	($1,708)	$0	($1)	($1)	($17)	($103)	($107)	($110)	($119)	($132)	($131)	($133)	($153)	($178)	($194)	($206)	($209)	($221)	($231)	($264)	($286)	($235)	($241)	($246)	($252)	($214)	($219)	($224)	($230)	($234)	($239)	($245)	($251)	($256)	($261)
Net (Benefit)/Cost	($92)	$0	($1)	($1)	$5	$66	$48	$29	$8	($12)	($21)	($27)	($56)	($84)	($78)	$35	$30	$15	$4	($32)	($55)	($5)	($11)	($17)	($24)	$1	($4)	($8)	($13)	($16)	($18)	($19)	($17)	($22)	($506)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																			
NPC	($1,249)	$0	$0	$1	($13)	($95)	($97)	($99)	($104)	($117)	($114)	($115)	($135)	($144)	($162)	($171)	($175)	($176)	($177)	($74)	($3)	($157)	($161)	($164)	($168)	($143)	($146)	($150)	($154)	($156)	($160)	($163)	($168)	($171)	($175)
Emissions	($33)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($8)	($9)	($10)	($11)	($5)	($2)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($7)	($7)	($7)	($7)	($7)
Other Variable Costs	($115)	$0	($1)	($1)	($2)	($4)	($6)	($6)	($7)	($7)	($9)	($10)	($11)	($13)	($15)	($17)	($19)	($14)	($17)	($14)	($12)	($16)	($17)	($17)	($17)	($15)	($15)	($15)	($16)	($16)	($16)	($17)	($17)	($18)	($18)
System Fixed Costs	($385)	$0	$0	$0	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($22)	($22)	($22)	($22)	($39)	($45)	($202)	($299)	($71)	($72)	($74)	($76)	($65)	($66)	($67)	($69)	($71)	($72)	($74)	($76)	($77)	($79)
Net System Impacts	($1,782)	$0	($0)	($1)	($16)	($103)	($106)	($109)	($118)	($132)	($130)	($133)	($153)	($179)	($207)	($218)	($226)	($238)	($250)	($295)	($316)	($251)	($256)	($262)	($269)	($229)	($234)	($239)	($245)	($249)	($255)	($261)	($268)	($272)	($278)
Net (Benefit)/Cost	($167)	$0	($0)	($1)	$6	$67	$48	$30	$8	($12)	($20)	($27)	($56)	($85)	($91)	$23	$13	($1)	($16)	($63)	($85)	($20)	($27)	($33)	($41)	($13)	($18)	($23)	($28)	($31)	($34)	($35)	($33)	($38)	($523)

Exhibit No. PAC/703

Estimated Annual Revenue Requirement Results ($ million)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																				
Transmission Project Capital Recovery	$602		$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)		$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220		$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83		$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492		$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)		$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99		$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
System Impacts																																				
NPC	($1,146)		$0	$0	$1	($13)	($85)	($86)	($88)	($92)	($104)	($101)	($101)	($119)	($129)	($144)	($154)	($169)	($80)	($82)	($147)	($148)	($147)	($150)	($153)	($157)	($134)	($137)	($140)	($143)	($146)	($149)	($153)	($157)	($159)	($163)
Emissions	($200)		$0	$0	$0	$0	$0	$0	$0	$0	$0	($10)	($20)	($29)	($35)	($38)	($36)	($42)	($21)	($22)	($32)	($34)	($36)	($37)	($38)	($39)	($33)	($34)	($35)	($35)	($36)	($37)	($38)	($39)	($39)	($40)
Other Variable Costs	($122)		$0	($1)	($1)	($2)	($5)	($6)	($6)	($7)	($8)	($9)	($10)	($10)	($13)	($16)	($16)	($16)	($16)	($17)	($18)	($24)	($17)	($18)	($18)	($19)	($16)	($16)	($17)	($17)	($17)	($18)	($18)	($19)	($19)	($19)
System Fixed Costs	($451)		$0	$0	$0	($0)	($19)	($19)	($20)	($24)	($24)	($25)	($25)	($26)	($38)	($38)	($39)	($21)	($147)	($148)	($73)	($76)	($70)	($72)	($73)	($75)	($64)	($65)	($67)	($69)	($70)	($71)	($73)	($75)	($76)	($78)
Net System Impacts	($1,920)		$0	($0)	($1)	($16)	($108)	($112)	($114)	($123)	($136)	($144)	($156)	($184)	($214)	($236)	($244)	($248)	($264)	($269)	($270)	($283)	($271)	($277)	($283)	($290)	($247)	($252)	($258)	($265)	($269)	($275)	($281)	($289)	($294)	($301)
Net (Benefit)/Cost	($304)		$0	($0)	($1)	$6	$61	$43	$25	$4	($17)	($35)	($50)	($88)	($120)	($120)	($3)	($9)	($27)	($35)	($38)	($51)	($40)	($47)	($54)	($62)	($31)	($37)	($42)	($48)	($51)	($54)	($56)	($55)	($60)	($545)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																				
Transmission Project Capital Recovery	$602		$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)		$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220		$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83		$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492		$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)		$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99		$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616		$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																				
NPC	($1,452)		$0	$0	$1	($19)	($115)	($122)	($113)	($118)	($123)	($122)	($122)	($143)	($159)	($173)	($154)	($109)	($176)	($152)	($227)	($214)	($184)	($189)	($193)	($198)	($168)	($172)	($176)	($180)	($184)	($188)	($192)	($197)	($200)	($205)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($129)		$0	($1)	($1)	($2)	($4)	($4)	($6)	($8)	($9)	($9)	($9)	($10)	($11)	($13)	($15)	($15)	($27)	($33)	($16)	($20)	($19)	($19)	($20)	($20)	($17)	($18)	($18)	($19)	($19)	($19)	($20)	($20)	($21)	($21)
System Fixed Costs	($483)		$0	$0	($0)	($0)	($3)	($3)	($27)	($30)	($31)	($32)	($32)	($33)	($41)	($55)	($92)	($147)	($57)	($99)	($41)	($67)	($77)	($79)	($80)	($83)	($70)	($72)	($73)	($75)	($77)	($78)	($80)	($82)	($84)	($86)
Net System Impacts	($2,063)		$0	($0)	($1)	($22)	($122)	($129)	($146)	($157)	($163)	($162)	($164)	($186)	($211)	($241)	($261)	($271)	($260)	($284)	($284)	($300)	($281)	($287)	($293)	($301)	($256)	($261)	($267)	($274)	($279)	($285)	($292)	($299)	($305)	($311)
Net (Benefit)/Cost	($448)	$0	($0)	($1)	$0	$47	$25	($7)	($31)	($43)	($52)	($58)	($90)	($117)	($125)	($19)	($32)	($23)	($49)	($52)	($69)	($50)	($57)	($65)	($73)	($40)	($46)	($51)	($58)	($61)	($64)	($66)	($65)	($71)	($556)	$0

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																				
Transmission Project Capital Recovery	$602		$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)		$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220		$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83		$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492		$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)		$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99		$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616		$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																				
NPC	($1,365)		$0	$0	$1	($19)	($115)	($122)	($99)	($101)	($107)	($105)	($106)	($125)	($138)	($153)	($110)	($120)	($171)	($165)	($237)	($249)	($176)	($180)	($184)	($189)	($161)	($164)	($168)	($172)	($175)	($179)	($183)	($188)	($191)	($196)
Emissions	($38)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6)	($4)	($6)	($10)	($10)	($14)	($17)	($7)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($8)	($8)	($8)	($8)	($8)
Other Variable Costs	($132)		$0	($1)	($1)	($2)	($4)	($4)	($5)	($8)	($9)	($9)	($10)	($10)	($11)	($13)	($14)	($14)	($29)	($33)	($19)	($22)	($20)	($20)	($20)	($21)	($18)	($18)	($19)	($19)	($19)	($20)	($20)	($21)	($21)	($22)
System Fixed Costs	($580)		$0	$0	($0)	($0)	($3)	($3)	($48)	($52)	($53)	($54)	($55)	($56)	($63)	($76)	($138)	($129)	($62)	($83)	($27)	($25)	($84)	($86)	($88)	($90)	($77)	($79)	($80)	($83)	($84)	($86)	($88)	($90)	($92)	($94)
Net System Impacts	($2,115)		$0	($0)	($1)	($22)	($122)	($129)	($152)	($160)	($168)	($168)	($170)	($191)	($213)	($248)	($267)	($269)	($271)	($291)	($297)	($314)	($288)	($294)	($301)	($308)	($262)	($268)	($274)	($281)	($286)	($293)	($299)	($307)	($312)	($319)
Net (Benefit)/Cost	($499)		$0	($0)	($1)	$0	$47	$25	($13)	($34)	($49)	($58)	($65)	($94)	($119)	($132)	($26)	($30)	($35)	($57)	($64)	($83)	($57)	($65)	($72)	($80)	($46)	($52)	($58)	($65)	($68)	($72)	($74)	($73)	($78)	($564)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																				
Transmission Project Capital Recovery	$602		$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)		$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220		$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83		$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492		$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)		$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99		$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616		$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																				
NPC	($1,432)		$0	$0	$1	($19)	($112)	($119)	($75)	($75)	($79)	($77)	($76)	($93)	($121)	($151)	($208)	($202)	($183)	($211)	($275)	($279)	($204)	($209)	($213)	($219)	($186)	($190)	($194)	($200)	($203)	($208)	($212)	($218)	($222)	($227)
Emissions	($178)		$0	$0	$0	$0	$0	$0	$0	$0	$0	($7)	($14)	($18)	($23)	($23)	($17)	($34)	($35)	($40)	($43)	($44)	($33)	($33)	($34)	($35)	($30)	($30)	($31)	($32)	($33)	($33)	($34)	($35)	($36)	($36)
Other Variable Costs	($112)		$0	($1)	($1)	($2)	($4)	($4)	($5)	($6)	($7)	($7)	($8)	($8)	($9)	($10)	($14)	($14)	($27)	($18)	($18)	($24)	($17)	($17)	($17)	($18)	($15)	($16)	($16)	($16)	($17)	($17)	($17)	($18)	($18)	($19)
System Fixed Costs	($530)		$0	$0	($0)	($0)	($7)	($7)	($84)	($89)	($91)	($93)	($95)	($97)	($77)	($74)	($44)	($23)	($49)	($41)	$17	$13	($53)	($54)	($56)	($57)	($48)	($50)	($51)	($52)	($53)	($54)	($55)	($57)	($58)	($59)
Net System Impacts	($2,251)		$0	($0)	($1)	($21)	($123)	($130)	($165)	($170)	($177)	($184)	($193)	($215)	($230)	($258)	($283)	($273)	($294)	($309)	($318)	($334)	($307)	($314)	($321)	($329)	($280)	($286)	($292)	($300)	($305)	($312)	($319)	($327)	($333)	($341)
Net (Benefit)/Cost	($635)		$0	($0)	($1)	$0	$46	$25	($25)	($44)	($57)	($74)	($87)	($118)	($136)	($142)	($42)	($34)	($58)	($75)	($86)	($103)	($77)	($84)	($92)	($101)	($64)	($70)	($76)	($83)	($87)	($91)	($93)	($93)	($99)	($586)

REDACTED
Docket No. UE 374
Exhibit PAC/704
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Rick T. Link

Confidential Summary Planned Capital Investments

February 2020

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REDACTED
Docket No. UE 374
Exhibit PAC/705
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

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Exhibit Accompanying Direct Testimony of Rick T. Link

Confidential Jim Bridger Plant Coal Costs

February 2020

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Docket No. UE 374
Exhibit PAC/706
Witness: Rick T. Link

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Confidential Contributions to Mine Reclamation Trust

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Docket No. UE 374
Exhibit PAC/707
Witness: Rick T. Link

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Confidential Jim Bridger Coal Company Mine Capital Costs

February 2020

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Docket No. UE 374
Exhibit PAC/708
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

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Exhibit Accompanying Direct Testimony of Rick T. Link

Confidential Natural Gas Price Assumptions used in the Evaluation of Jim Bridger Units 3 and 4

February 2020

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Docket No. UE 374
Exhibit PAC/709
Witness: Rick T. Link

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Confidential System Optimizer Model Results for Gas Price Scenarios

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Docket No. UE 374
Exhibit PAC/710
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Exhibit Accompanying Direct Testimony of Rick T. Link

Relationship between Gas Prices and the PVRR

February 2020

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Docket No. UE 374
Exhibit PAC/711
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Exhibit Accompanying Direct Testimony of Rick T. Link

Relationship between CO2 Prices and the PVRR

February 2020

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REDACTED
Docket No. UE 374
Exhibit PAC/800
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Chad A. Teply

February 2020

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ATTACHED EXHIBITS

Confidential Exhibit PAC/801—Energy Vision 2020 Wind Capital Cost Comparison

Exhibit PAC/802—Site Plan Ekola Flats

Confidential Exhibit PAC/803—Ekola Flats Assessment and Wind Resource and Energy Production Estimate

Confidential Exhibit PAC/804—Ekola Flats Project Schedule

Exhibit PAC/805—Large Generator Interconnection Agreement Ekola Flats

Confidential Exhibit PAC/806—Ekola Flats Easements

Exhibit PAC/807—Permit Status Record Ekola Flats

Exhibit PAC/808—Site Plan TB Flats

Confidential Exhibit PAC/809—TB Flats Assessment, Wind Resource and Energy Production Estimate, and Wind Resource Assessment Review

Confidential Exhibit PAC/810—TB Flats Project Schedule

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp.

A. My name is Chad A. Teply and my business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116. I am currently employed as Senior Vice President of Business Policy and Development. I am testifying for PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science Degree in Mechanical Engineering from South Dakota State University. I joined MidAmerican Energy Company in November 1999, and held positions of increasing responsibility within the generation organization, including serving as project manager for development and construction of a new 780 megawatt (MW) supercritical coal-fueled generation resource placed in service in 2007. In April 2008, I moved to Northern Natural Gas Company as Senior Director of Engineering. I joined PacifiCorp in February 2009. My current responsibilities encompass strategic planning, stakeholder engagement, regulatory support, and development and execution of major generation resource additions, major transmission projects, and major environmental compliance projects.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to address the new wind projects that are included in Energy Vision 2020, the Pryor Mountain Wind Project, certain major emissions control retrofit projects, and the natural gas conversion of Naughton Unit 3.

First, as explained by Mr. Stefan A. Bird, PacifiCorp developed an energy resource strategy, Energy Vision 2020, comprised of two components: repowering existing wind resources and implementation of new wind and transmission projects. Energy Vision 2020 was assessed in the Company's 2017 Integrated Resource Plan (IRP) preferred portfolio, which identified a time-limited opportunity to procure approximately 1,100 MW of cost-effective Wyoming wind facilities and construct transmission facilities to relieve existing congestion and allow interconnection of those new wind facilities, while providing all-in customer savings. In my testimony and exhibits, I discuss and support the Energy Vision 2020 new wind projects and demonstrate the reasonableness of their costs. Mr. Richard A. Vail's testimony provides the same for the related transmission projects, Mr. Timothy J. Hemstreet's testimony supports PacifiCorp's Foote Creek I wind repowering project, and Mr. Rick T. Link provides the economic analysis demonstrating the net benefits associated with PacifiCorp's Energy Vision 2020 projects.

Second, I explain and support the Company's development and implementation of the Pryor Mountain Wind Project and show that the costs are reasonable. The Pryor Mountain Wind Project, located in Carbon County, Montana, was identified as an opportunity to acquire and implement a late-stage renewables development project to capture 100 percent federal production tax credits (PTC) if acted on expeditiously to deliver the project by year-end 2020. In addition to providing PTCs and net power cost benefits, the project also allows the Company to meet a customer need for incremental renewable energy certificates (RECs), the purchase of which under PacifiCorp's Oregon Schedule 272 - Renewable Energy

Rider Optional Bulk Purchase Option (Schedule 272), further improves the project's economics and associated customer benefits.

Third, my testimony supports the prudence of major emissions control retrofit projects included in this case and placed in service during major maintenance overhauls at Jim Bridger Units 3-4 in November 2015 and November 2016, respectively, Hunter Unit 1 in May 2014, Craig Unit 2 in December 2017, and Hayden Units 1-2 in May 2015 and August 2016, respectively, all of which were installed in accordance with state and federal environmental compliance requirements for the individual units. More specifically, my testimony supports the prudence of the installation of selective catalytic reduction (SCR) systems on Jim Bridger Units 3-4, Craig Unit 2, and Hayden Units 1-2, and the installation of low nitrogen oxides (NO_X) burners and a baghouse on Hunter Unit 1. Each of those projects were installed to ensure environmental compliance for the respective units, as well as continued safe, reliable, and cost-effective operation of the facilities. The impact on Oregon revenue requirement for the projects is reflected in the testimony of Ms. Shelley E. McCoy, and Mr. Link provides the economic analysis demonstrating the customer benefit of the projects.

Finally, I explain the natural gas conversion of Naughton Unit 3 following its removal from coal-fired operation on January 30, 2019, to maintain compliance with certain environmental regulations. Conversion of Naughton Unit 3 to a natural gas fueled resource is facilitated by the design of the unit which already incorporates natural gas fueling infrastructure for start-up. This underlying infrastructure can be readily and economically modified to facilitate generation up to 247 MW of capacity from the unit within applicable environmental permit limits for periods of peak loads across PacifiCorp's system to benefit our customers.

Q. Please summarize your direct testimony.

A. My testimony demonstrates that:

- the acquisition and construction of TB Flats I and II, Cedar Springs II, and Ekola Flats (collectively referred to as the Energy Vision 2020 Wind Projects or individually as an Energy Vision 2020 Wind Project) and the associated transmission facilities described in the testimony of Mr. Vail that form Energy Vision 2020 (collectively, the Combined Projects) are prudent and in the public interest. The Combined Projects will provide substantial customer benefits after they achieve commercial operation by the end of 2020. My testimony explains how the Company has developed, procured, and implemented the Energy Vision 2020 Wind Projects to deliver this outcome.

- the acquisition and construction of the Pryor Mountain Wind Project is prudent and in the public interest. As with the Energy Vision 2020 Wind Projects, the Pryor Mountain Wind Project has been acquired, developed, procured, and implemented to achieve commercial operation by the end of 2020 to deliver significant PTC benefits, as well as incremental customer benefits derived from the associated Schedule 272 REC sale.

- the installation of major emissions control retrofits for Hunter Unit 1, Jim Bridger Units 3-4, Craig Unit 2, and Hayden Units 1-2 are prudent and in the public interest. The emissions control retrofit projects included in this case and described further in testimony below were required to comply with environmental laws, namely the Clean Air Act Regional Haze Rules, established by the U.S. Environmental Protection Agency (EPA) and administered by the respective state agencies in which the units reside.

- completion of natural gas conversion of Naughton Unit 3 is prudent and in the public interest. The natural gas conversion project included in this case and described further in testimony below is *de minimis* in scope and facilitates operation of a significant generation resource during periods of peak loads across PacifiCorp's system for the benefit of customers.

III. ENERGY VISION 2020 OVERVIEW

Q. Please provide an overview of the Combined Projects as identified and presented in the 2017 IRP.

A. To support its participation in the 2017 Renewables Request for Proposals (2017R RFP) included in the 2017 IRP Action Plan, PacifiCorp secured development and implementation rights for the 250 MW Ekola Flats wind project and the 500 MW TB Flats I and II wind project, which were ultimately selected from competitive market respondents as successful final shortlist projects in the 2017R RFP. In addition, the 2017R RFP final shortlist resulted in PacifiCorp executing a power purchase agreement (PPA) for the third-party delivered 200 MW Cedar Springs I wind project and a build-transfer agreement (BTA) for procurement of the third-party delivered 200 MW Cedar Springs II wind project. The competitive market solicitation conducted through the 2017R RFP confirmed the economics and deliverability of these specific wind facilities, which are now under construction and on schedule to be delivered before year-end 2020.

The Energy Vision 2020 Wind Projects rely upon the construction of the Aeolus to Bridger/Anticline transmission line and associated network upgrades, which will relieve existing congestion and allow interconnection of the Energy Vision 2020 Wind Projects. In turn, the benefits generated by the Energy Vision Wind Projects—zero-fuel-cost generation that lowers net power costs and provide 10 years of federal PTCs—support cost-effective development of the transmission projects. Together, the Combined Projects provide significant savings to customers over the lives of the resources. As further detailed in the testimony of Mr. Vail, the transmission facilities are also currently under construction and on schedule for delivery before year-end 2020.

Q. Why is the Company implementing acquisition and construction of the Combined Projects?

A. As further described in the testimony of Mr. Link, the Company is implementing the acquisition and construction of the Combined Projects to deliver a time-sensitive opportunity for customers that was identified in the Company's 2017 IRP preferred portfolio (*i.e.*, addition of approximately 1,100 MW of new wind resources and the associated new transmission infrastructure by 2020). Following competitive market engagement in the 2017R RFP, the Company has executed the necessary agreements to ensure that the Energy Vision 2020 Wind Projects have effective implementation plans and are positioned to support the associated transmission facilities.

Q. Before proceeding, did PacifiCorp obtain the required state regulatory approvals for the Combined Projects?

A. Yes. To capture the substantial customer benefits resulting from this time-limited opportunity and in accordance with applicable state regulatory statutes, PacifiCorp received approval of Certificates of Public Convenience and Necessity (CPCN) from the Wyoming Public Service Commission (Wyoming CPCN) and the Idaho Public Utilities Commission (Idaho CPCN) for the Combined Projects. PacifiCorp also received approval orders from the Utah Public Service Commission approving the "significant energy resource decision" for the construction or acquisition of the new wind facilities and "voluntary procurement preapproval" for the construction of the associated transmission facilities (Utah Preapproval).

IV. GENERAL DESCRIPTION OF THE ENERGY VISION 2020 WIND PROJECTS

Q. Please describe the Energy Vision 2020 Wind Projects.

A. The Energy Vision 2020 Wind Projects information incorporated into this general rate case filing is intended to allow the Public Utility Commission of Oregon (Commission) to review the prudence and customer benefits of the Energy Vision 2020 Wind Projects as validated through the 2017R RFP. As outlined above, the Energy Vision 2020 Wind Projects include: (1) the 250 MW Ekola Flats facility; (2) the 500 MW TB Flats I and II facility; (3) the nominal 200 MW Cedar Springs II facility; and (4) the 200 MW Cedar Springs I facility that will provide energy to PacifiCorp's system through a PPA. My testimony focuses on the facilities that will ultimately be owned and operated by PacifiCorp, which excludes the Cedar Springs I PPA.

Each wind facility will consist of a number of 2.0 MW to 4.3 MW wind turbine generators (WTG) to achieve the facility's respective nameplate capacity, an electrical collection system, 34.5 kilovolt (kV) to 230 kV collector substation(s), a 230 kV tie-line between the wind project and the point of interconnection substation, meteorological towers, access roads, an operations and maintenance (O&M) building and required communication and control facilities (*e.g.*, metering, hardware, software, and associated communication circuits and related equipment).

The cost for the Energy Vision 2020 Wind Projects included in this case are approximately $1.23 billion.

Q. Please provide a summary of the capital expenditures required to construct the Energy Vision 2020 Wind Projects.

A. Confidential Exhibit PAC/801 to my testimony includes the summary.

Q. Please describe the time-sensitive nature of the Combined Projects.

A. The time-sensitive nature of the Combined Projects is primarily driven by the pending phase-out of federal PTCs for new wind resources and the time period involved to construct a major transmission line. In Internal Revenue Code section 45, the Internal Revenue Service (IRS) provides for PTCs at the 2017 full rate of 2.4 cents per kilowatt-hour of electrical energy production by a wind facility. The PTCs are available for a 10-year period that begins when the facility is placed in service. The Protecting Americans from Tax Hikes Act of 2015 (the PATH Act) extended the availability of the PTCs for wind facilities under construction before January 1, 2020. The PATH Act extension, however, also provides for a phase-out of the PTCs. Wind facilities that began construction before January 1, 2017, per IRS rules, will realize the full PTC credit, which is the case for the Energy Vision 2020 Wind Projects. If a wind facility begins construction in 2017, the PTCs are reduced by 20 percent. The PTCs are reduced by 40 percent if construction begins in 2018, and by 60 percent if construction begins in 2019. PTCs are not available for wind facilities that begin construction after December 31, 2019.

To receive "safe-harbor" PTCs, the facilities must be placed into commercial operation by the end of the fourth calendar year following the year in which construction began (the start-of-construction standard) or otherwise meet specific IRS requirements for demonstrating the "continuity requirement" throughout the implementation timeline. To ensure customers receive the full benefit of safe-harbor PTCs the Combined Projects (and other wind facilities selected in the 2017R RFP) must have begun construction before January 1, 2017, and must be placed in service by year-end 2020. The Company's acquisition and implementation plan is designed to meet this schedule and provide customers the full economic benefit of the PTCs.

Q. Do the Energy Vision 2020 Wind Projects meet the IRS's start-of-construction criteria?

A. Yes. Each of the Energy Vision 2020 Wind Projects will use WTG equipment acquired before December 31, 2016. These transactions satisfy the safe-harbor requirements under the PTC guidance issued by the IRS.

Q. Did the Company's submittal of benchmark resources in the 2017R RFP preclude other competitive market proposals from being selected for implementation?

A. No. As explained in the testimony of Mr. Link, the Company's benchmark resources (Ekola Flats and TB Flats I and II) represent only a portion of the competitive market wind facilities that were determined to be viable in the 2017R RFP considering interconnection, permitting, construction, performance, and implementation. PacifiCorp received a robust competitive market response to the 2017R RFP, with the Company's benchmark resources ultimately being successful in that process, in addition to the third-party Cedar Springs projects described above.

Q. What is the current construction status of the Energy Vision 2020 Wind Projects?

A. For TB Flats I and II, 116 of 132 WTG foundations have been constructed; WTG access roads are complete; foundations for both collector substations are complete; structural steel erection is approximately 40 percent and 68 percent complete at the TB Flats I and TB Flats II collector substations, respectively; underground collector cable installation is approximately 86 percent and 27 percent complete at the TB Flats I and TB Flats II areas, respectively; manufacturing, testing, and delivery of five main power transformers are on schedule to support spring 2020 delivery to the site; and manufacturing of follow-on WTGs continues in support of component delivery to the site beginning in April 2020.[1]

For Ekola Flats, 20 of 63 WTG foundations have been constructed; WTG access roads are complete; foundations at the collector substation are complete; certain directional borings have been completed in support of underground collector cable installation; manufacturing, testing, and delivery of two main power transformers are on schedule to support spring 2020 delivery to the site; and manufacturing of the follow-on WTGs continues in support of component delivery to the site beginning in June 2020.

For the Cedar Springs II BTA project, the project achieved the contractual Firm Date on November 7, 2019, which is a pre-closing date indicative of completion and transition from project development activities to field construction; detailed

[1] Follow-on WTGs are the non-safe harbor WTG components, and the safe harbor WTG components are currently located in storage offsite.

engineering work continues (including WTG layout adjustments in support of U.S Fish and Wildlife avian mitigation guidance), site rough grading of the collector substation has commenced, and work has begun on the transmission tie-line between the Cedar Springs II and the Cedar Springs I (NextEra PPA) collector substations.

Q. What is the status of the WTG agreements for the Energy Vision 2020 Wind Projects?

A. With respect to WTG supply agreements, Vestas - American Wind Technology, Inc. (Vestas) was originally competitively selected in the third quarter of 2017 as the follow-on WTG supplier for the Ekola Flats and TB Flats projects. On November 14, 2018, PacifiCorp received a letter from Vestas communicating that it was unable to hold pricing for the WTGs due to: (1) steel pricing risk; (2) tariffs on Chinese goods; and (3) increased transportation costs. In response, PacifiCorp investigated the conditions associated with the Vestas letter and consequently initiated a competitive market request for proposal (RFP) update exercise with all originally shortlisted WTG suppliers beginning on November 15, 2018. The shortlisted suppliers from this update were asked to confirm their positions on pricing and availability in conformity with permit conditions and constraints. Final firm price proposals were received on January 21, 2019. PacifiCorp completed an assessment of life cycle costs associated with the updated proposals. Both 2.* MW and 4.* MW[2] WTG platform options from multiple WTG suppliers were compared. Ultimately, the assessment concluded that the Ekola Flats and TB Flats project initial capital cost estimates for WTG supply

[2] The asterisk used in 2.* MW and 4.* MW is a common industry wildcard designation when referring to a range of available WTGs capacities within turbine design platforms of various original equipment manufacturers.

would exceed the estimates included in PacifiCorp's original CPCN filings. As I discuss in more detail below, however, when considered in conjunction with updated run rate O&M cost reductions included in the new proposals and remaining Combined Projects contingencies, the increased costs were effectively offset and not assessed as creating a material challenge to the overall benefit and ultimate deliverability of the Combined Projects.

WTG component deliveries for all of the Energy Vision 2020 Wind Projects will begin in spring 2020.

Q. Has the Company performed preliminary evaluations of the wind potential at each Energy Vision 2020 Wind Project site?

A. Yes. Wind potential studies for each of the Energy Vision 2020 Wind Projects were completed by the individual project developers and were also validated with a third-party wind resource evaluation firm as part of the 2017R RFP process. As reflected in Confidential Table 1, wind assessments for each of the Energy Vision 2020 Wind Projects indicate that the sites have favorable wind regimes suitable for high performance wind energy generation. Pertinent wind potential assessments including expected capacity factors are included in Exhibits PAC/802, PAC/808, and PAC/814.

Confidential Table 1: Energy Vision 2020 Wind Project Capacity Factor Estimates

EV 2020 Net Capacity Factors (P50 Assessment)		
Project Name	Project Size (Nameplate MWs)	Project Net Capacity Factor
Ekola Flats	250.9	[redacted]
TB Flats I and II	503.2	
Cedar Springs II BTA	199.8	

The 2017R RFP evaluation team also reviewed the wind resource assessments for each project and independently determined whether the wind data for each project supported the proposed capacity factors or whether adjustments to the proposed capacity factor for a project were warranted when assessing project benefits.

Q. Is the Company collaborating with the U.S. Fish and Wildlife Service in developing and implementing the Energy Vision 2020 Wind Projects?

A. Yes. The Company has engaged the U.S. Fish and Wildlife Service regarding developing and implementing the Energy Vision 2020 Wind Projects. The Company, or with respect to the Cedar Springs projects, the third-party developer, has begun pre-construction usage surveys for various avian, bat, and wildlife species utilizing recommendations from applicable state and federal guideline documents, including the 2012 Land Based Wind Energy Guidelines. The Company will continue to coordinate with county, state, and federal agencies that have jurisdiction over development, permitting, and operations to ensure appropriate environmental and safety measures are implemented throughout the life of the Energy Vision 2020 Wind Projects. The Company is committed to maintaining development and implementation schedules and protocols that recognize potential environmental impacts and strive to mitigate them.

Q. How did the Company generate the cost information for construction, operation, and maintenance of the individual wind facilities through their useful life?

A. The Company assessed life cycle costs for the Energy Vision 2020 Wind Projects using information submitted by the various project proponents in the 2017R RFP and validated against a variety of sources. For example, initial installation costs and run rate O&M cost projections were incorporated into the respective facility's 2017R RFP proposals. Transmission interconnection costs were confirmed against the respective wind facility's transmission interconnection studies. PacifiCorp's internal project management and administrative costs were estimated based on the Company's experience with construction of past wind facilities and other recent generation resource additions.

The Company also applied contingencies to the Ekola Flats and TB Flats I and II self-build projects to account for project uncertainties. The third-party developer of the Cedar Springs II project is responsible for the contingencies included to deliver that project. O&M cost estimates were developed based on the Company's experience with currently operating wind facility O&M budgets and third-party contracts for the Company's existing wind facilities. Ongoing capital costs were estimated based on the Company's experience and indicative costs provided by WTG suppliers for critical capital components.

Q. In terms of managing implementation of the Combined Projects to meet the December 31, 2020 PTC deadline, what were the critical path items?

A. The critical path items were obtaining the CPCNs and pre-approvals necessary to allow PacifiCorp to begin work on the Aeolus to Bridger/Anticline transmission line. To meet the December 31, 2020 deadline for the Combined Projects, PacifiCorp had to have these regulatory approvals and make its investment decision before the summer of 2018, to allow sufficient time to obtain rights of way and permits for the Aeolus to Bridger/Anticline transmission line. PacifiCorp received the Wyoming CPCN in April 2018 and Utah Preapproval in June 2018, and made the decision to proceed with the Combined Projects shortly thereafter (the Idaho CPCN was issued slightly later, in July 2018). PacifiCorp's decision to invest in the Combined Projects was based on the Company's February 2018 economic analysis, adjusted in April 2018 to remove the Uinta project.

Q. Have there been any material changes to the scope or overall economics of the Combined Projects since PacifiCorp began work on the Aeolus to Bridger/Anticline transmission line in the summer of 2018?

A. No. Project permitting and rights of way acquisition proceeded as planned for the Ekola Flats and TB Flats projects and the associated 500 kV transmission facilities. As noted above, an issue did arise related to U.S. tariff impacts and other unfavorable market conditions, which negatively impacted previously established WTG equipment supply pricing and competitive market costs for the 230 kV transmission facilities.

The increased costs for the 230 kV transmission facilities were absorbed in project contingencies carried in the 500 kV transmission facilities and therefore had no negative impact on originally assessed customer benefits for the Energy Vision 2020 projects.

The U.S. tariff impacts on Ekola Flats and TB Flats WTG equipment required PacifiCorp to re-engage the originally shortlisted WTG suppliers for the Ekola Flats and TB Flats projects to submit updated WTG capital costs, run rate O&M costs, and equipment performance information. In Table 2 below, the Company compared the updated information to the originally assessed life-cycle cost and benefit information. This analysis demonstrated that the competitive market update and reassessment resulted in a slight increase in customer benefits when compared to the Company's February 2018 economic analysis, as adjusted to remove the Uinta project:

Table 2: Annual Revenue Requirement Present-Value Revenue Requirement Differential (PVRR(d)) through 2050 (Benefit) / Cost of the Projects ($ millions)

Price-Policy Scenario	Updated Annual Revenue Requirement PVRR(d)	Original Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	152	154
Medium Gas, Medium CO_2	(176)	(174)

Q. What is the expected operational life of the Energy Vision 2020 Wind Projects?

A. The anticipated operational life of the Energy Vision 2020 Wind Projects has been assessed at 30 years, which aligns with the Company's currently approved depreciable life for wind resources.

Q. When did construction of the Energy Vision 2020 Wind Projects begin?

A. Site construction of the Energy Vision 2020 Wind Projects began in mid-2019 following receipt of all necessary regulatory approvals and applicable permits and authorizations from other local, state, tribal or federal governmental agencies that have jurisdiction over the construction or operation of the Energy Vision 2020 Wind Projects, including approval from the Wyoming Industrial Siting Council. The Company anticipates that substantial completion, under normal construction circumstances, weather conditions, labor availability and materials delivery, will be achieved by November 15, 2020, for the Ekola Flats and TB Flats projects and by December 31, 2020, for Cedar Springs II.

Q. Please explain why the Energy Vision 2020 Wind Projects are prudent and in the public interest.

A. The information and analysis in the Company's 2017 IRP and in this case demonstrate that the Energy Vision 2020 Wind Projects are prudent and in the public interest. The Energy Vision 2020 Wind Projects provide a range of benefits to PacifiCorp's Oregon customers, including PTCs, net power cost savings, RECs that may be sold or used for Renewable Portfolio Standard compliance, reduced emissions, and generation diversification. The Energy Vision 2020 Wind Projects will become an essential element of the Company's diversified resource portfolio that is needed to serve customers, and as described more fully in the testimony of Mr. Link and Mr. Vail, the Energy Vision 2020 Wind Projects and associated transmission projects will provide net benefits to all customers.

Q. Please describe your exhibits for the 250 MW Ekola Flats facility.

A. Information for the 250 MW Ekola Flats facility is identified as follows:

- Exhibit PAC/802—Site Plan Ekola Flats
- Confidential Exhibit PAC/803—Ekola Flats Assessment and Wind Resource and Energy Production Estimate
- Confidential Exhibit PAC/804— Ekola Flats Project Schedule
- Exhibit PAC/805— Large Generator Interconnection Agreement Ekola Flats
- Confidential Exhibit PAC/806— Ekola Flats Easements
- Exhibit PAC/807— Permit Status Record Ekola Fats

Q. Please describe the exhibits to your testimony for the 500 MW TB Flats wind facility.

A. Information for the 500 MW TB Flats wind facility is identified as follows:

- Exhibit PAC/808— Site Plan TB Flats
- Confidential Exhibit PAC/809— TB Flats Assessment, Wind Resource and Energy Production Estimate, and Wind Resource Assessment Review
- Confidential Exhibit PAC/810— TB Flats Project Schedule
- Exhibit PAC/811— Large Generator Interconnection Agreement TB Flats
- Confidential Exhibit PAC/812— TB Flats Easements
- Exhibit PAC/813— TB Flats Permit Status Record

Q. Please describe the exhibits for the 200 MW Cedar Springs II wind facility.

A. Information for the 200 MW Cedar Springs II wind facility is identified as follows:

- Exhibit PAC/814— Site Plan Cedar Springs
- Confidential Exhibit PAC/815— Cedar Springs Assessment and Wind Energy Analysis
- Confidential Exhibit PAC/816— Cedar Springs Project Schedule
- Exhibit PAC/817— Large Generator Interconnection Agreement Cedar Springs
- Confidential Exhibit PAC/818— Cedar Springs Rights of Way
- Exhibit PAC/819— Permit Status Record Cedar Springs

V. PRYOR MOUNTAIN WIND PROJECT

Q. Please provide an overview of the Pryor Mountain Wind Project.

A. The Pryor Mountain Wind Project will have a nameplate capacity of 240 MW. The facility will be located on a site in Carbon County, Montana, approximately 60 miles south of Billings, Montana. The project consists of 57 Vestas Model 110-2.0 MW safe harbor, 21 Vestas Model 110-2.2 MW safe harbor, four General Electric Model 116-2.3 MW safe harbor, and 32 Vestas model 110-2.2 MW follow-on WTGs. In addition to the wind turbines there will be a 34.5 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. A new point of interconnection substation located on the project site in Montana will also be constructed. The planned in-service date for the project is December 2020. Based on current regulatory practice, the project has been assessed using a depreciable life of 30 years.

Q. Please provide background on PacifiCorp's development of the Pryor Mountain Wind Project.

A. The opportunity to capture customer benefits resulting from the acquisition, development, and implementation of the Pryor Mountain Wind Project was identified and evolved over a compressed timeline beginning in October 2018 and ending with final terms on all material agreements (*i.e.*, the engineer, procure, and construct (EPC) contract and WTG supply agreements) completed by September 30, 2019. In parallel, negotiation of a Schedule 272 REC purchase agreement for the sale of all RECs associated with the output of the Pryor Mountain Wind Project to Vitesse, LLC (Vitesse) began in December 2018 and final terms were reached in late June 2019. The process from initial discussions to negotiation of final terms of the Schedule 272 REC purchase agreement occurred in under six months.

The Pryor Mountain wind project costs included in this case are approximately [redacted].

Q. Please provide a summary of the capital expenditures required to construct the Pryor Mountain wind project.

A. Confidential Exhibit PAC/820 includes the summary.

Q. Please describe the time-sensitive nature of the federal PTCs as it pertains to the Pryor Mountain Wind Project.

A. Similar to the Energy Vision 2020 Wind Projects, the time-sensitive nature of the Pryor Mountain Wind Project is primarily driven by the pending phase-out of the federal PTCs for new wind resources. With an in-service date before the end of 2020, the Pryor Mountain Wind Project will be eligible for the full rate (100 percent) of the PTCs as described earlier in my testimony. The Pryor Mountain Wind Project will deploy safe harbor WTG equipment to achieve eligibility. The Company's acquisition and implementation plan for the Pryor Mountain Wind Project is designed to meet the year-end 2020 in-service schedule and provide customers the full economic benefit of the project.

Q. Does the Pryor Mountain Wind Project meet the IRS's start-of-construction criteria as described earlier in your testimony?

A. Yes. The Pryor Mountain Wind Project will utilize WTG equipment acquired before December 31, 2016. The WTG equipment acquisitions satisfy the safe-harbor requirements under the PTC guidance issued by the IRS.

Q. What approach was taken to secure late-stage development safe harbor wind turbine generator equipment and follow-on WTG equipment for the Pryor Mountain Wind Project?

A. The Vestas safe harbor WTG equipment identified above was sourced and will be acquired and transferred under an affiliate transaction with Berkshire Hathaway Energy Renewables (BHER). The four General Electric safe harbor WTG's described above were directly procured by the Company in 2016. PacifiCorp completed a competitive market solicitation for the follow-on WTG equipment required to complete the nominal 240 MW Pryor Mountain Wind Project. The combination of utilizing PacifiCorp's safe harbor equipment, the transferred BHER safe harbor equipment, and competitive market engagement for follow-on WTG equipment limited exposure to competitive market constraints and pricing volatility for 2020 delivery of 100 percent PTC projects with the safe harbor equipment already manufactured and awaiting delivery.

Q. What is the current construction status of the Pryor Mountain Wind Project?

A. The Pryor Mountain Wind Project will primarily be constructed in 2020, although in 2019 site activities began with completion of geotechnical borings and surveys, other site surveys and detailed engineering, construction of a material laydown area, and installation of approximately five percent of WTG access roads. A ramp up of site construction activities will occur in spring 2020 as winter weather in Montana improves.

Q. Has the Company performed preliminary evaluations of the wind potential at the Pryor Mountain Wind Project site?

A. Yes. A wind potential study for the Pryor Mountain Wind Project was completed by a third-party wind resource evaluation firm. The wind potential assessments for Pryor Mountain indicates that the site has a favorable wind regime suitable for high performance wind energy generation. The expected capacity factor for the project is described in the exhibits to my testimony, but for ease of reference is provided here as [redacted] and aligns with the assumptions made in support of the economics evaluation of the project.

Q. Is the Company collaborating with the U.S. Fish and Wildlife Service in developing and implementing the Pryor Mountain Wind Project?

A. Yes. The Company has engaged the U.S. Fish and Wildlife Service regarding developing and implementing the Pryor Mountain Wind Project. The Company and the project's previous owner and developers began pre-construction usage surveys for various avian, bat, and wildlife species utilizing recommendations from applicable state and federal guideline documents, including the 2012 Land Based Wind Energy Guidelines. The Company will continue to coordinate with county, state, and federal agencies that have jurisdiction over development, permitting, and operations to ensure appropriate environmental and safety measures are implemented throughout the life of the Pryor Mountain Wind Project. The Company is committed to maintaining development and implementation schedules and protocols that recognize potential environmental impacts and strive to mitigate them.

Q. How did the Company assess the customer benefits provided by the Pryor Mountain Wind Project?

A. Mr. Link provides a detailed description of the Company's customer benefits assessment in his testimony. In general terms, the methodology used to perform the economic analysis of the Pryor Mountain Wind Project is consistent with the methodology used to perform the economic analysis of bids submitted into the Company's 2017R RFP, which ultimately resulted in selection of the Energy Vision 2020 Wind Projects. PacifiCorp's economic analysis reflects the significant benefits from the sale of RECs associated with the Pryor Mountain Wind Project.

Q. How did the Company generate the cost information for construction, operation, and maintenance of the Pryor Mountain Wind Project through its useful life?

A. Consistent with the Energy Vision 2020 Wind Projects, the Company assessed life cycle costs for the Pryor Mountain Wind Project using information from a variety of sources. For example, initial installation costs and run rate O&M cost projections were developed through competitive market engagements for project construction and WTG supply and long-term O&M contracts. Transmission interconnection costs were confirmed against the Pryor Mountain Wind Project's transmission interconnection studies. PacifiCorp's internal project management and administrative costs were estimated based on the Company's experience with construction of past and current wind facilities and other recent generation resource additions. The Company also applied limited contingencies to the Pryor Mountain Wind Project to account for project uncertainties. O&M cost estimates were developed based on the Company's experience with currently operating wind facility O&M budgets and third-party contracts for the Company's existing wind facilities. Ongoing capital costs were estimated based upon the Company's experience and indicative costs provided by WTG suppliers for critical capital components.

Q. Please describe the exhibits for the 240 MW Pryor Mountain Wind Project.

A. Information for the 240 MW Pryor Mountain Wind Project is identified as follows:

- Exhibit PAC/821—Site Plan Pryor Mountain
- Confidential Exhibit PAC/822—Wind Potential Assessment Pryor Mountain
- Confidential Exhibit PAC/823—Project Schedule Pryor Mountain
- Exhibit PAC/824—Large Generator Interconnection Agreement Pryor Mountain

- Confidential Exhibit PAC/825—Pryor Mountain Rights of Way
- Exhibit PAC/826—Permit Status Record Pryor Mountain

VI. EMISSIONS CONTROL RETROFIT PROJECTS

Q. Please provide a summary of the Company's cost to complete the emissions control retrofit projects included in this proceeding.

A. The cost of the Jim Bridger Unit 3 SCR project included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on an Oregon-allocated basis, and the cost of the Jim Bridger Unit 4 SCR project included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on an Oregon-allocated basis. The cost of the Hunter Unit 1 low NO_X burners and baghouse projects included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on an Oregon-allocated basis. The cost of the Craig Unit 2 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on an Oregon-allocated basis. The cost of the Hayden Unit 1 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on an Oregon-allocated basis, and the cost of the Hayden Unit 2 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on an Oregon-allocated basis.

Q. Which other Company witnesses in this proceeding provide testimony regarding the prudence of the emissions control retrofit projects included in this case?

A. Mr. Link provides testimony explaining the economic analysis used by the Company to support its decision to proceed with installation of the emissions control retrofit project included in this proceeding. These capital additions are included in the existing rate base reflected in the revenue requirement incorporated in the exhibits of Ms. McCoy.

Jim Bridger Units 3-4 SCRs

Q. Describe the Jim Bridger plant and the operating features of Units 3-4.

A. The Jim Bridger facility is a 2,123 MW, four-unit mine-mouth coal-fired electrical generating facility located in Sweetwater County, Wyoming, which is two-thirds co-owned by PacifiCorp and one-third co-owned by the Idaho Power Company. The plant is maintained and operated by PacifiCorp. Water for operation is conveyed approximately 40 miles through a pipeline originating at a diversion from the Green River. Unit 3 began commercial operation in 1976 and Unit 4 followed in 1979. Unit 3 and Unit 4 have nominal net (or "net reliable") generation capacities of 523 and 530 MW, respectively, of which the corresponding PacifiCorp two-thirds share is 349 and 353 MW. Both units are configured with Alstom (formerly Combustion Engineering) controlled circulation, tangentially fired, pulverized coal boilers and General Electric steam turbine-generators. Both units are configured with closed loop circulating water cooling systems that include mechanical draft cooling towers and electrostatic precipitators. Unit 4 was originally equipped with a sodium-based wet flue gas desulfurization (FGD) system, and Unit 3 was retrofitted in 1985 with a sodium-based wet FGD system.

The Jim Bridger substation is contiguous to the plant and connects six transmission lines: Populus #1 at 345 kV, Populus #2 at 345 kV, Threemile Knoll at 345 kV, Rock Springs at 230 kV, Point of Rocks at 230 kV and Mustang at 230 kV.

An additional 345 kV line connecting to the Energy Vision 2020 Aeolus – Anticline 500 kV transmission line is currently under construction.

The plant is adjacent to PacifiCorp's and Idaho Power Company's co-owned Bridger mine, which supplies sub-bituminous coal to the plant along a 2.4-mile long, 42-inch wide overland belt conveyor. Additional sub-bituminous coal is delivered to the plant from other mines in southwestern Wyoming via rail or truck. Coal combustion residuals (CCR) are disposed of on plant property in a solid waste landfill and a FGD waste surface impoundment.

Q. Please provide a general description of the Jim Bridger Units 3-4 SCR systems.

A. The Jim Bridger Units 3-4 SCR systems and associated ancillary equipment for each unit serve to control oxides of nitrogen emissions. Each SCR system is comprised of two separate reactors, with multiple catalyst levels; inlet and outlet ductwork; a shared ammonia reagent system; an economizer upgrade; structural reinforcement of the boiler, air preheater, and flue gas path ductwork and equipment; power distribution and electrical infrastructure installation and integration with the existing plant; and an extension of the existing plant-wide distributed control system. An induced draft fan upgrade and a corresponding auxiliary power system variable frequency drive insertion was also required for Unit 4 only.

Q. What was the required timeline for the Company to install the SCR systems at Jim Bridger Units 3-4?

A. The Clean Air Act Regional Haze Rules, the Jim Bridger facility Best Available Retrofit Technology (BART) permit issued by the state of Wyoming, a BART appeal settlement agreement with the state of Wyoming, and the Wyoming Regional Haze

State Implementation Plan (SIP) required the installation of the SCR systems on Unit 3 by the end of 2015, and on Unit 4 by the end of 2016.

Q. Did EPA approve the state of Wyoming's Regional Haze SIP compliance requirements for Jim Bridger Units 3-4?

A. Yes. EPA approved these requirements in its final Regional Haze Federal Implementation Plan (FIP) for Wyoming published in the *Federal Register* on June 4, 2012. EPA subsequently reiterated its approval of these requirements in its updated Regional Haze FIP for Wyoming published in the *Federal Register* on January 30, 2014. EPA's final approval made these emissions reduction compliance requirements at Jim Bridger Units 3-4 federally enforceable, in addition to being enforceable under state law.

Q. How did the Company assess the benefits associated with the Jim Bridger SCR projects described?

A. The Company began its detailed economic assessment of the projects in 2012 to support its Wyoming CPCN filing (Wyoming SCR CPCN) and its Utah Voluntary Resource Procurement Decision filings for the projects. The Company used the same analysis methodology and results to support its 2013 IRP filings and updates across its service territory states. The proceedings associated with these various filings provided stakeholders an opportunity for rigorous review of the projects prior to their implementation in the 2013 through 2016 timeframe, as facilitated by the statutes available and procedural schedules used by the public utility commissions in each state. The Company's economic analyses are detailed in the testimony of Mr. Link.

The economic analyses completed demonstrate that both of these projects were prudent, necessary, and in the best interests of our customers.

Q. Do the SCR systems at Jim Bridger Units 3-4 have the same general purpose and scope?

A. Yes. For this reason, my testimony references the SCR systems at both Jim Bridger Units 3-4.

Q. Did the Company file an application for a CPCN for the Jim Bridger Units 3-4 SCR systems in the state of Wyoming, where the projects are constructed?

A. Yes. On August 7, 2012, the Company filed its application requesting a CPCN[3] with the Wyoming Public Service Commission, in compliance with the Stipulation and Agreement (2010 Wyoming Stipulation) approved in Wyoming docket 20000-384-ER-10 (2010 Wyoming Rate Case), to construct two major environmental projects as provided in paragraph 13.b. of the 2010 Wyoming Stipulation. The projects entailed the addition of SCR systems to Units 3-4 of the Jim Bridger electric generating plant located in Sweetwater County, Wyoming.

Q. Did the Company file a Voluntary Request for Approval of Resource Decision to Construct the Jim Bridger Units 3-4 SCR systems in the state of Utah?

A. Yes. On August 24, 2012, the Company filed its application requesting the Public Service Commission of Utah review and approve in advance of construction the Jim Bridger SCR projects.[4]

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[3] *In the matter of the Application of Rocky Mountain Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4 Located Near Point of Rocks, Wyoming,* Docket No. 20000-418-EA-12, Order No. 21555 (May 29, 2013).
[4] *In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4,* Docket No. 12-035-92. Order (May 10, 2013), Order of Clarification (May 30, 2013).

Q. Did the Company include analysis of the Jim Bridger Units 3-4 SCR systems in the Company's 2013 IRP filings?

A. Yes. The Company filed Confidential Volume III of the 2013 IRP on April 30, 2013.[5] Confidential Volume III included detailed analysis of the Jim Bridger Units 3-4 SCR systems. Regarding the 2013 IRP, in Order No. 14-252, it is my understanding that the Commission did not acknowledge the action item related to the installation of SCRs at Jim Bridger Units 3-4 noting that it would review a number of issues including prudence in a future rate case proceeding.[6]

Q. How was the Jim Bridger Units 3-4 SCR systems project cost information incorporated into the Company's Wyoming SCR CPCN and Utah Resource Decision applications compare to the Company's 2013 IRP analysis of the project?

A. The Company used the same project cost information as the baseline for the Wyoming SCR CPCN and Utah Resource Decision applications, as well as for the Company's 2013 IRP filings.

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[5] Confidential Volume III of the 2013 IRP was filed in Idaho, Oregon, Utah, Washington, and Wyoming. For Oregon, *see In the Matter of PacifiCorp, d/b/a Pacific Power 2013 Integrated Resource Plan,* Docket No. LC 57, PacifiCorp's 2013 Integrated Resource Plan, Vol. III (Apr. 30, 2013).
[6] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2013 Integrated Resource Plan*, Docket No. LC 57, Order No. 14-252, 8-9 (Jul. 8, 2014).

Q. Did the Public Service Commission of Utah approve the Company's request for a Resource Decision?

A. Yes. On May 10, 2013, the Public Service Commission of Utah approved the Company's request for a Resource Decision to add SCR systems on Jim Bridger Units 3-4.[7]

Q. Did the Wyoming Public Service Commission approve the Company's request for a CPCN?

A. Yes. On May 29, 2013, the Wyoming Public Service Commission approved the Company's request for a CPCN to add SCR systems on Jim Bridger Units 3-4.[8]

Q. Before executing the EPC contract, did the Company engage in a multi-year process to develop, study, review, and obtain initial regulatory approvals for the Bridger SCRs?

A. Yes. This process began with the issuance of Wyoming's SIP in 2008, which led to a lengthy environmental permitting process. In August 2012, the Company initiated a CPCN proceeding in Wyoming and a pre-approval proceeding in Utah, resulting in highly scrutinized and publicized regulatory reviews that lasted until May 2013. In April 2013, the Company completed its 2013 IRP, which contained a comprehensive review of the Bridger SCRs.

[7] *In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4,* Docket No. 12-035-92. Order, 34 (May 10, 2013).
[8] *In the matter of the Application of Rocky Mountain Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4 Located Near Point of Rocks, Wyoming,* Docket No. 20000-418-EA-12, Order No. 21555, 17-18 (May 29, 2013).

Q. Did the detailed evaluation of the Bridger SCRs that occurred as part of this multi-year process inform the Company's decision to move forward with this investment?

A. Yes. The Bridger SCRs were fully vetted in numerous different processes, helping to confirm that they were the best compliance option for customers.

Q. Have you prepared a timeline of the Bridger SCR projects from the draft Wyoming SIP to the final completion date?

A. Yes. Figure 1 contains a list of the major milestones for the Bridger SCR projects.

Figure 1—Bridger SCRs Timeline

Date	Milestone
May 22, 2008	Wyoming Regional Haze SIP (revised)
December 31, 2009	Jim Bridger BART Permit
February 26, 2010	PacifiCorp Appeal of BART Permit
November 2, 2010	Wyoming BART Appeal Settlement (Bridger SCR Requirement)
December 23, 2010	Jim Bridger BART Permit Amendment
January 7, 2011	Wyoming Regional Haze SIP (revised)
June 4, 2012	EPA Wyoming FIP Proposal
August 7, 2012	Wyoming CPCN Application
August 24, 2012	Utah Pre-approval Application
February 11, 2013	Utah Pre-approval Rebuttal
March 4, 2013	Wyoming CPCN Rebuttal
April 30, 2013	PacifiCorp 2013 IRP Confidential Volume III Filed
May 10, 2013	Utah Pre-approval Order
May 30, 2013	Wyoming CPCN Approval Order
May 31, 2013	EPC Limited Notice to Proceed
June 28, 2013	Idaho Power Company's Wyoming CPCN Application
December 1, 2013	EPC Final Notice to Proceed
December 2, 2013	Idaho Power Company's Wyoming CPCN Approval Order
January 30, 2014	EPA Wyoming FIP Final Action
March 31, 2014	PacifiCorp 2013 IRP Update Confidential Exhibit F Filed
November 2015	Jim Bridger 3 SCR in service
December 30, 2015	Wyoming GRC Order
December 31, 2015	Jim Bridger 3 SCR Compliance Deadline
November 2016	Jim Bridger 4 SCR in service
December 31, 2016	Jim Bridger 4 SCR Compliance Deadline

Q. When was the EPC contract executed and the contractor released to begin work?

A. The Jim Bridger Units 3-4 SCR EPC contract was executed by the parties on May 31, 2013. The EPC contract included a limited notice to proceed (LNTP) provision that initially released the selected EPC contractor to begin scheduled critical activities only for a period of time while parallel path permitting and regulatory proceedings (e.g., environmental agency Regional Haze activities and IRP reviews) continued. The Company gave full notice to proceed (FNTP) to the EPC contractor effective on December 1, 2013, under negotiated EPC contract provisions that were established to maintain project cost and schedule certainty. The EPC contractor's construction site mobilization began in December 2013.

Q. Did the Company update its original Confidential Volume III analysis of the Jim Bridger Units 3-4 SCR systems?

A. Yes. The Company included its updated analysis of the Jim Bridger Units 3-4 SCR projects in Confidential Appendix F in its 2013 IRP Update completed on March 31, 2014, which specifically addressed potential changes in carbon regulation and natural gas market cost impacts.

Q. Did the Company's updated review of potential carbon regulation and natural gas forward price curves in its March 31, 2014 IRP Update filing result in changes to its earlier economic analysis of the Jim Bridger Units 3-4 SCR systems?

A. No. The forecast proxy costs for carbon regulations and natural gas included in the 2013 IRP Update remained within the ranges initially assessed.

Q. What was the Company's cost to complete the Jim Bridger Unit 3 SCR system?

A. The cost of the Jim Bridger Unit 3 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on an Oregon-allocated basis. The total-company cost to complete the Jim Bridger Unit 3

SCR system was approximately [redacted] less than the corresponding cost originally assessed in the Wyoming CPCN and Utah Resource Decision applications, as well as in the 2013 IRP. A cost comparison is shown in Confidential Exhibit PAC/827.

Q. Did the Company prudently manage the implementation of the Jim Bridger Unit 3 SCR system?

A. Yes. Beyond management of project costs as mentioned above, the Company's project team prudently implemented and maintained an appropriate procurement strategy, project controls, and status reporting to ensure compliance with contract safety program implementation, technical specification requirements, scope of work definition, critical path schedules, quality assurance, commissioning plans, and turnover to operations plans, among other things.

Q. What is the major maintenance overhaul cycle interval for Jim Bridger Units 3-4?

A. Jim Bridger Units 3-4 are maintained on a four-year maintenance outage cycle based on the Company's operating experience with the Jim Bridger units. The outage cycle has been established to optimize unit reliability and availability, while maintaining an appropriate balance of major maintenance outage scope and costs. The implementation schedules of the Jim Bridger SCR projects were aligned with the established major maintenance overhaul cycles for the individual units.

Q. What is the current status of the Jim Bridger Unit 3 SCR system?

A. The Jim Bridger Unit 3 SCR system was placed in service in November 2015, following the planned major maintenance overhaul for Unit 3. The Company's environmental compliance deadline as established by the governing permits, implementation plans, and agreements described earlier in this testimony was December 31, 2015, for Unit 3. Completion of the Jim Bridger Unit 3 SCR system satisfied the compliance deadlines established for the unit, as well as the prescribed emissions reductions.

Q. Please confirm that the drivers, general description, and rationale for the Jim Bridger Unit 4 SCR system was consistent with that provided above for the Jim Bridger Unit 3 SCR system.

A. The drivers, general description, and rationale for the Jim Bridger Unit 4 SCR system all mirror the information provided above for the Jim Bridger Unit 3 SCR system.

Q. When was the Unit 4 EPC contract executed and the contractor released to begin work?

A. A single EPC contract was executed for the Jim Bridger Units 3-4 SCR systems, the timeline of which is described above.

Q. What was the Company's cost to complete the Jim Bridger Unit 4 SCR system?

A. The cost of the Jim Bridger Unit 4 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on an Oregon-allocated basis. The Company's total-company cost to complete the Jim Bridger Unit 4 SCR system was approximately [redacted] less than the corresponding cost originally assessed in the Wyoming SCR CPCN and Utah Resource Decision applications, as well as in the 2013 IRP. A cost comparison is shown in Confidential Exhibit PAC/828.

Q. Did the Company prudently manage implementation of the Jim Bridger Unit 4 SCR system?

A. Yes. The testimony I provided above relating to the prudent management of the Jim Bridger Unit 3 SCR system is also applicable to the Jim Bridger Unit 4 SCR system.

Q. What is the current status of the Jim Bridger Unit 4 SCR system?

A. The Jim Bridger Unit 4 SCR system was placed in service in November 2016, following the planned major maintenance overhaul for Unit 4. The Company's environmental compliance deadline as established by the governing permits, implementation plans, and agreements described earlier in this testimony was December 31, 2016, for Unit 4. Completion of the Jim Bridger Unit 4 SCR system satisfied the compliance deadlines established for the unit, as well as the prescribed emissions reductions.

Q. Why did the Company not defer the start of planning for the SCRs until after the EPA's final action in January 2014?

A. The Company was required to comply with the timelines set in Wyoming's SIP. Considering the complexity of the Bridger SCRs and the lengthy project timeline, the Utah Public Service Commission and the Wyoming Public Service Commission found the timing of the Company's investment was appropriate.

Q. Did the Company query the state of Wyoming regarding the enforceability and applicability of its obligations under the SIP?

A. Yes. The state of Wyoming responded that the Company was required to comply with the deadlines set in the Wyoming SIP. The Company's request and the state's response are attached as Exhibit PAC/829 and Exhibit PAC/830, respectively.

Hunter Unit 1 Low NO_X Burners (LNB) and Baghouse

Q. Please describe the Hunter facility and Hunter Unit 1 in particular.

A. The Hunter plant is a three-unit coal-fueled power plant with a net generation capacity of approximately 1,363 MW. The plant is located approximately 158 miles south of Salt Lake City, Utah, near the town of Castle Dale, Utah. Unit 1 is 93.8 percent owned by the Company and 6.2 percent owned by the Utah Municipal Power Agency, with the Company responsible for operation and maintenance of the unit and the Hunter plant as a whole.

Units 1-2 are basically identical units when considering their base design and originally installed boiler and steam turbine generator equipment. Unit 3 is identical in layout to Units 1-2 except the boiler and turbine are from different manufacturers.

Water for plant use is released into the Cottonwood Creek from Joe's Valley and conveyed by a direct pipeline from the Millsite Reservoir to the plant. Potable water is piped from the cities of Castle Dale, Utah or Clawson, Utah. Hunter is a zero-discharge plant. The balance of water is evaporated from a pond or used for irrigation of hay crops on the adjacent research farm. Plant sewage is treated and discharged to the evaporation pond.

Coal is supplied by belt from the nearby fuels preparation facility owned by Wolverine Fuels, LLC, that blends coal to a specified contracted coal quality, allowing for combustion of various coal types.

Q. Please describe the Hunter Unit 1 baghouse conversion project and associated equipment.

A. The Hunter Unit 1 baghouse conversion project replaced the originally installed particulate matter (PM) control equipment (electrostatic precipitator) on the unit with a best available retrofit technology baghouse to meet the Company's emissions compliance obligations required by the Regional Haze Rules and incorporated into the state of Utah's Regional Haze SIP and associated permits to be installed by spring 2014. The baghouse captures PM and mercury from the flue gas stream as it passes through the equipment. Capturing mercury in the baghouse allows the unit to comply with the EPA's Mercury and Air Toxics Standards (MATS) requirements for mercury capture by the prescribed deadline of April 16, 2015, without installing incremental stand-alone mercury emissions control equipment. The dry particulate waste stream captured in the baghouse is transported to an on-site landfill for disposal.

An additional emissions control benefit that the baghouse brings to Unit 1 is the ability to close the scrubber bypass currently installed on the unit, which when considered in conjunction with the Hunter Unit 1 scrubber, reagent preparation, and waste handling projects completed on the unit in 2012 allows the unit to meet a reduced sulfur dioxide (SO_2) emissions limit required by the state of Utah Regional Haze SIP and associated permits.

Other equipment installed as part of the baghouse project included upgraded booster fans, boiler reinforcement, new ductwork, modifications to the existing chimney, relocation of the stack opacity monitors, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

The Company's share of the capital investment for the baghouse conversion project included in this proceeding is [redacted] on a total-company basis. Construction of the project was completed and placed in service following a planned major maintenance outage on the unit in May 2014. The final project cost was approximately [redacted] less than the cost initially assessed during the economic analysis and authorization for expenditure stage of the project.

Q. Please describe the Hunter Unit 1 LNB installation project.

A. The LNB installation project on Hunter Unit 1 includes the installation of NO_X combustion controls that replace originally installed equipment. The new burners utilize improved combustion characteristics and a separated over-fire air supply to the boiler to reduce NO_X emissions.

The Company's share of the capital investment for the project included in this proceeding is [redacted] on a total-company basis. The project was completed and placed in service following the same major maintenance outage on the unit referenced above. The final project cost was approximately [redacted] less than the cost initially assessed during the economic analysis and authorization for expenditure stage of the project.

Q. Have Hunter Units 2 and 3 been equipped with LNB and baghouse retrofit technologies that provide emissions reductions consistent with those being installed on Hunter Unit 1?

A. Yes. Pursuant to Utah Regional Haze SIP requirements, Unit 2 was equipped in 2011 with the same LNB and baghouse retrofit technologies contemplated in this docket for Hunter Unit 1. The same post-retrofit emissions limits for NO_X (0.26 pounds per million British thermal unit (Btu)) and PM (0.015 pounds per million Btu) are required for each unit. The Commission reviewed the Unit 2 emissions control equipment investments for ratemaking purposes in a past general rate case docket. The Unit 2 equipment is included in the Company's rate base.

Unit 3 was equipped with a fabric filter baghouse (1983) when the unit was originally constructed and was retrofitted with LNB technology in 2007. The Unit 3 LNB investment was included in the Company's approved rate base in docket UE 210. The Unit 3 LNB equipment is included in the Company's rate base.

All three Hunter units are equipped with wet lime scrubbers to control sulfur dioxide emissions to a rate of 0.12 pounds per million Btu.

Hunter Unit 1 Projects Drivers and Alternatives Assessments

Q. What were the key permits and/or regulations requiring the Hunter Unit 1 baghouse and LNB projects to be installed?

A. To continue compliant operation of Hunter Unit 1, the Company was required to install the projects described herein to control emissions of NO_X, PM, and SO_2 criteria pollutants as required by Regional Haze Rules, the state of Utah's § 309 (g) Implementation Plan, the state of Utah's BART review process, and the state of Utah's Approval Order (DAQE-AN0102370012-08) dated March 2008. Figure 2 below is a general timeline of the significant regulatory actions and regulations.

Figure 2

Date	Milestone
August 8, 2004	Utah SO_2 SIP
June 15, 2005	Regional Haze Rules Finalized
2007	Multiple Hunter Plant Notice of Intent Filed
March 13, 2008	Hunter Plant Approval Order
September 9, 2008	Utah Regional Haze SIP Submittal
May 26, 2011	Regional Haze SIP Update
June 2012	Hunter 1 APR and EPC Contract
December 14, 2012	EPA Approval, Disapproval, Promulgation of 2011 Utah SIP Final
January 2013	Hunter 1 PM/NO_X Construction Start (LNB work)
May 2014	Hunter 1 PM/NO_X Tie-in Outage

The state of Utah Regional Haze SIP and permit requirements for the Hunter Unit 1 projects were finalized in 2008; detailed economic assessment of compliance alternatives and competitive procurement activities were completed in 2012; construction of the project began in 2013; and the baghouse conversion project was placed in service following a planned major maintenance outage on the unit in spring 2014. Additional background regarding the Regional Haze compliance obligations facing Hunter Unit 1 is provided in Exhibit PAC/831.

Q. Did the Company evaluate whether the risk-adjusted, least-cost alternative to comply with environmental requirements was to invest in the emissions control equipment included in this case or to idle Hunter Unit 1?

A. Yes. Before executing the EPC contract for the baghouse project in June 2012, the Company evaluated alternatives to comply with environmental requirements other than to complete the project. The Company used its System Optimizer Model to evaluate multiple alternatives. In brief, the major alternatives reviewed were:

(1) Continue to operate and incur operating expenses and capital revenue requirement expenses inclusive of incremental environmental investments;

(2) Retire Hunter Unit 1 and replace with resource alternatives, or;

(3) Convert to natural gas as a compliance alternative to the incremental environmental investments planned for the unit as a coal-fueled facility.

The comparison of various alternatives resulted in a PVRR(d) of [redacted] favorable to proceeding with the project to the next best alternative as selected by the System Optimizer Model. The next best alternative was to convert Hunter Unit 1 to a natural gas fueled facility. Confidential Exhibit PAC/832 provides detailed discussion of the Company's analyses and results.

Q. Were the methods and tools used to assess the compliance alternatives for Hunter Unit 1 consistent with those utilized to support the Company's 2013 IRP filings,[9] as well as the Company's Jim Bridger Units 3-4 CPCN filing in Wyoming and its Jim Bridger Units 3-4 Voluntary Procurement Pre-approval filing in Utah?

A. Yes. The Company utilized consistent methods and tools (e.g. System Optimizer Model) to assess compliance alternatives for Hunter Unit 1 as was done in the Company's other major filings regarding environmental compliance investments in coal-fueled resources. In fact, the Company included the results of its Hunter Unit 1 analyses in its 2013 IRP Confidential Volume III.

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[12] Action Item 8B in the Company's 2013 IRP was to complete installation of the baghouse conversion and low NO_X burner compliance projects at Hunter Unit 1 as required by the end of 2014. In Order 14-252, the Commission declined to acknowledge Action Item 8b because the Company did not bring the Commission the Hunter 1 investments in its 2011 IRP and investment decisions were substantially complete at the time of the 2013 IRP. The Commission found that it "... will expect PacifiCorp to provide adequate analysis when it seeks recovery of these projects." *See In the Matter of PacifiCorp d/b/a Pacific Power, 2013 Integrated Resource Plan,* Docket No. LC 57, Order No. 14-252 at 7 (Jul. 8, 2014).

Q. Does the Hunter Unit 1 baghouse conversion project provide emissions compliance benefits beyond those required by the Utah Regional Haze SIP?

A. Yes. The Hunter Unit 1 baghouse conversion project provides emissions compliance benefits associated with the EPA's MATS regulations.

Q. Beyond directly reducing mercury emissions, how is the Hunter Unit 1 baghouse project expected to allow Hunter Unit 1 to meet other EPA's MATS regulations?

A. In addition to specific emissions requirements for mercury, MATS includes requirements for emissions of non-mercury metals. MATS non-mercury metals emissions compliance can be demonstrated via a surrogate PM emissions limit of 0.030 pounds filterable PM per million Btu. The baghouse allows Hunter Unit 1 to comply with that portion of MATS.

With respect to mercury emissions control, the Hunter 1 baghouse allows the unit to comply with MATS mercury emissions limits without the need to install activated carbon injection equipment for mercury removal purposes, avoiding those incremental costs as well.

Craig Unit 2 SCR

Q. Please describe the Craig facility.

A. The Craig facility is a three-unit coal-fired electrical generating facility located in Moffat County, Colorado. Units 1-2 (837 MW), are jointly owned by Tri-State Generation and Transmission Association, Inc. (Tri-State), Salt River Project, Platte River Power Authority, Public Service Company of Colorado (PSCo), and PacifiCorp (PacifiCorp owns 19.28 percent of the units). Unit 3 is solely owned by Tri-State. Tri-State operates all units at the facility.

Q. Please provide a general description of the Craig Unit 2 SCR system.

A. Generally consistent with the description provided for the Jim Bridger Units 3-4 SCRs, the Craig Unit 2 SCR system is primarily comprised of a reactor with multiple catalyst levels; inlet and outlet ductwork; an ammonia reagent system; certain boiler structure and ancillary infrastructure retrofits; electrical and control system installation and integration with the existing plant.

Q. What was the required timeline for Tri-State to install the SCR system at Craig Unit 2?

A. The Craig Unit 2 SCR was required by the Clean Air Act Regional Haze Rules and the associated state of Colorado Regional Haze SIP to be installed by January 30, 2018. Colorado's Regional Haze SIP was first approved by the Colorado Air Quality Control Commission in January 2011, and was submitted to EPA for review and approval on May 25, 2011.

Q. Did EPA approve the State of Colorado's Regional Haze SIP compliance requirements for Craig Unit 2?

A. Yes. EPA published its approval of the Colorado Regional Haze SIP compliance requirements for Craig Unit 2 in the *Federal Register* on December 31, 2012. EPA's final rule became effective January 30, 2013.[10]

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[13] The Company did not include the Craig Unit 2 SCR investment as an action item in the 2013 IRP filed in Docket No. LC 57. While noting that these investments should not be an action item, the Commission directed the Company to hold a technical workshop to review existing analysis on the investment. *See In the Matter of PacifiCorp d/b/a Pacific Power, 2013 Integrated Resource Plan,* Docket No. LC 57, Order No. 14-252 at 10 (Jul. 8, 2014). A special public meeting was held on August 6, 2014 to provide the requested analysis. The meeting was confidential, limited to parties subject to the confidentiality provisions included with Docket No. LC 57. *See In the Matter of PacifiCorp d/b/a Pacific Power, 2015 Integrated Resource Plan,* Docket No. LC 62, 2015 Integrated Resource Plan, Vol. II, App. B at 29 (filed Mar. 31, 2015).

Q. Please generally describe the joint ownership governance of Craig Unit 2.

A. The terms and conditions of joint ownership in Craig Unit 2 are governed by a Participation Agreement. The Participation Agreement mandates the installation of capital improvements that are required by applicable law. The Participation Agreement also places an independent obligation on Tri-State, as Operating Agent, to operate Craig Unit 2 in accordance with applicable laws. The applicable laws requiring the Craig Unit 2 SCR installation are discussed earlier in my testimony.

As Operating Agent, Tri-State is also responsible for development of operating budgets and capital investment recommendations to be set forth for joint owner review and approvals. The Participation Agreement's provisions for approval of capital expenditures requires that the proposed expenditures be included in the annual capital expenditure budget prepared by the Operating Agent and that the annual capital expenditure budget is approved by a majority vote (*i.e.* greater than 50 percent ownership share) of the joint owners.

Q. Did Tri-State request approval of the Craig Unit 2 SCR capital investment in accordance with the terms of the Participation Agreement and was it approved by greater than 50 percent ownership share of the joint owners?

A. Yes. Tri-State initially included costs associated with the Craig Unit 2 SCR in the 2013 capital expenditures budget for review and approval pursuant to the Participation Agreement. The project was approved by a greater than 50 percent ownership share of the joint owners.

Q. Did PacifiCorp independently assess the benefits associated with the Craig Unit 2 SCR project?

A. Yes. In July 2013, PacifiCorp independently assessed the benefits associated with the Craig Unit 2 SCR project against a hypothetical wherein PacifiCorp could unilaterally effectuate an accelerated shutdown of the unit. This hypothetical was not a realistic option because PacifiCorp cannot unilaterally effectuate an accelerated shutdown of the Craig units based on the language of the Participation Agreement. PacifiCorp's hypothetical did not support the installation of SCRs.

Q. What position did PacifiCorp take with respect to the Craig Unit 2 SCR project capital budget approval?

A. The Company voted no with respect to the Craig Unit 2 SCR project. PacifiCorp recognized that under the terms of the Participation Agreement its no vote alone would not change the outcome with the other joint-owners voting yes, and PacifiCorp remained obligated to pay its share of the Craig Unit 2 SCR.

Q. Did PacifiCorp also independently assess its legal options with respect to the capital expenditures approval process incorporated into the Participation Agreement?

A. Yes. In June 2013, PacifiCorp engaged internal and external counsel to independently assess PacifiCorp's rights under the Participation Agreement with respect to payment options and dispute resolution that may occur with a majority decision on capital expenditures that was not supported by PacifiCorp. The ultimate determination of the internal and external legal reviews of the Participation Agreement was that PacifiCorp had the right to challenge the majority's decision, but there was little to no opportunity to successfully challenge the project through arbitration or litigation. This was primarily because the project met the requirements under the Participation Agreements, specifically: (i) the project is required by applicable law (the Colorado Regional Haze SIP); (ii) Craig Unit 2 is required to be operated in accordance with applicable law under the Participation Agreement; and (iii) the majority of the Craig Unit 2 joint-owners (in fact all other than PacifiCorp) voted in support of the project.

Q. Considering the terms and conditions of the Participation Agreement, did PacifiCorp pursue arbitration or litigation of the Craig Unit 2 SCR project decision?

A. No, for the reasons explained above.

Q. What was the Company's cost to complete the Craig Unit 2 SCR system?

A. The cost of the Craig Unit 2 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on an Oregon-allocated basis with an in-service date of December 2017.

Q. What is the current status of the Craig Unit 2 SCR system?

A. The Craig Unit 2 SCR system was placed in service in December 2017, following the planned major maintenance overhaul for the unit. Completion of the Craig Unit 2 SCR system satisfied the compliance deadlines established for the unit, as well as the prescribed emissions reductions.

In each case, installation of these major emissions control retrofit projects have been aligned with scheduled major maintenance outages for the affected units to mitigate replacement power cost impacts while benefiting from overlapping major maintenance outage time frames. These environmental compliance projects allow the retrofitted facilities to continue to operate as low-cost generation resources for the benefit of customers.

Hayden Units 1 & 2 SCRs

Q. Please describe the Hayden Facility.

A. The Hayden plant is a 441 MW, two-unit coal-fired electrical generating facility located in Routt County, Colorado. Unit 1 is jointly owned by PSCo and PacifiCorp (PacifiCorp owns 24.5 percent). Unit 2 is jointly owned by PSCo, Salt River Project, and PacifiCorp (PacifiCorp owns 12.6 percent). PSCo operates the plant.

Q. Please provide a general description of the Hayden Units 1-2 SCR systems.

A. Generally consistent with the description provided for the Jim Bridger Units 3-4 SCRs, the Hayden Units 1-2 SCR systems are primarily comprised of: reactors with multiple catalyst levels; inlet and outlet ductwork; ammonia reagent systems; certain boiler structures and ancillary infrastructure retrofits; electrical and control systems installation; and integration with the existing plant.

Q. What was the required timeline for the Company to install the SCR systems at Hayden Units 1-2?

A. The Hayden Units 1-2 SCRs were required by the State of Colorado's Regional Haze SIP to be installed no later than December 31, 2016.

Q. Did EPA approve the state of Colorado's Regional Haze SIP compliance requirements for Hayden Units 1-2?

A. Yes. The EPA published its approval of the Colorado Regional Haze SIP in the

Federal Register on December 31, 2012.[11] EPA's final approval made these emissions reduction compliance requirements at Hayden Units 1-2 federally enforceable, in addition to being enforceable under state law.[12]

Q. What regulations required the Hayden Units 1-2 SCR projects to be installed?

A. In December 2010, the Colorado Air Quality Control Commission promulgated new BART determinations and emissions control requirements for the Hayden units in the Colorado Regional Haze SIP. These BART determinations set emissions limits of 0.08 lbs NO_X/million Btu (MMBtu) for Hayden Unit 1 and 0.07 lbs NO_X/MMBtu for Hayden Unit 2. Although the BART determinations did not specify how these limits were to be achieved, installation of SCRs was the only technically feasible method available.

Q. Was a CPCN acquired for the Hayden Units 1-2 SCR systems in the state of Colorado, where the projects were constructed?

A. On January 26, 2011, the Colorado Public Utilities Commission approved the installation of SCR systems on Hayden Units 1-2, finding that PSCo had demonstrated that the installation of the project was in the best interest of customers but still required the filing of a modified CPCN application primarily because the cost

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[14] http://www2.epa.gov/region8/air-program.
http://www2.epa.gov/sites/production/files/201402/documents/epafinalactioncoloradoregionalhazeplan.pdf.

[15] The Company did not include the Hayden Units 1 and 2 SCR investments as an action item in the 2013 IRP filed in Docket No. LC 57. While noting that these investments should not be an action item, the Commission directed the Company to hold a technical workshop to review existing analysis on the investments. *See In the Matter of PacifiCorp d/b/a Pacific Power, 2013 Integrated Resource Plan,* Docket No. LC 57, Order No. 14-252 at 10 (Jul. 8, 2014). A special public meeting was held on August 6, 2014 to provide the requested analysis. The meeting was confidential, limited to parties subject to the confidentiality provisions included with Docket No. LC 57. *See In the Matter of PacifiCorp d/b/a Pacific Power, 2015 Integrated Resource Plan,* Docket No. LC 62, PacifiCorp's 2015 Integrated Resource Plan, Vol. II, App. B at 29 (filed Mar. 31, 2015).

information presented was not adequate.[13] The Colorado Public Utilities Commission approved PSCo's CPCN application on July18, 2012.[14]

Q. Please generally describe the joint ownership governance of Hayden Units 1-2.

A. The terms and conditions of joint ownership in Hayden Units 1-2 are governed by a Participation Agreement. The Participation Agreement mandates the installation of capital improvements that are required by applicable law. The Participation Agreement also places an independent obligation on PSCo, as Operating Agent, to operate Hayden Units 1-2 in accordance with applicable laws. The applicable laws requiring the Hayden Units 1-2 SCR installation are discussed earlier in my testimony. PacifiCorp owns 24.5 percent of Unit 1 and 12.6 percent of Unit 2.

Q. What is the current status of the Hayden Units 1-2 SCR system?

A. The Hayden Units 1 and 2 SCR systems were placed in service in May 2015 and August 2016 respectively, following the planned major maintenance overhaul for the units. Completion of the Hayden Units 1-2 SCR systems satisfied the compliance deadlines established for the units, as well as the prescribed emissions reductions.

In each case, installation of these major emissions control retrofit projects have been aligned with scheduled major maintenance outages for the affected units to

[16] *In re Public Service Co. of Colorado's Plan in Compliance with House Bill 10-1365*, "Clean Air-Clean Jobs Act, Docket No. 10M-245E, Decision No. C10-1328 at pp. 44-45, 51, 86 (Jan. 26, 2011)(available at: http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0ahUKEwisv6r2xPHZAhXnr1QKHUt5BhYQFggnMAA&url=http%3A%2F%2Fwww.dora.state.co.us%2FPUC%2FDocketsDecisions%2Fdecisions%2F2010%2FC10-1328_10M-245E.doc&usg=AOvVaw016pmadIRvCs3VyPuOf5l).

[17] *In re Public Service Co. of Colorado's Application for a Certificate of Public Convenience and Necessity for the Hayden Emissions Control Project*, Docket No. 11A-917E, Decision No. C12-0843 at pp. 1, 6 (July 18, 2012)(available at https://www.dora.state.co.us/pls/efi/EFI_SEARCH_UI.SEARCH?p_session_id=&p_results=Documents&p_proceeding_number=11A917E&p_document_type=Choose%20One&p_docket_status=Choose%20One&p_decision_type=Choose%20One&p_decision_author=Choose%20One&p_auto_search=Y).

mitigate replacement power cost impacts while benefiting from overlapping major maintenance outage time frames. These environmental compliance projects allow the retrofitted facilities to continue to operate as low-cost generation resources for the benefit of customers.

Q. Were the emissions control retrofit projects included in this proceeding intended to extend the operational life of either Jim Bridger Units 3-4, Hunter Unit 1, Craig Unit 2, or Hayden Units 1-2?

A. No. The emissions control retrofit projects included in this proceeding were required to continue operations in Wyoming, Utah, and Colorado to meet state requirements. The Hayden Units 1-2 SCRs were key components of the NO_X reduction plan required by PSCo (the operator of Hayden Unit 1) to the Colorado Public Utilities Commission under the Colorado Clean Air Clean Jobs Act. The Colorado Public Utilities Commission approved PSCo's NO_X reduction plan, including the Hayden Units 1-2 SCRs on December 9, 2010.[15]

VII. NAUGHTON UNIT 3 GAS CONVERSION

Q. Please describe why Naughton Unit 3 is being converted to natural gas fueling.

A. The Company was required to cease coal-fired operations in Naughton Unit 3 on January 30, 2019, to maintain compliance with certain environmental regulations. Completion of natural gas conversion of Naughton Unit 3 will increase the unit's generating capacity when fueled by natural gas from 35 MW (utilizing existing start-up fuel infrastructure) to 247 MW.

[18] http://www.dora.state.co.us/PUC/DocketsDecisions/decisions/2010/C10-1328_10M-245E.pdf.

Q. Please describe the permitting process for Naughton Unit 3.

A. On July 5, 2013, the Wyoming Department of Environmental Quality (WDEQ) issued Air Permit MD 14506, which establishes natural gas emission and heat input limits for Naughton Unit 3 which would "become effective upon conversion" of Unit 3 to natural gas firing. On November 28, 2017, the WDEQ submitted to the EPA a regional haze SIP revision which required Naughton Unit 3 to cease burning coal no later than January 30, 2019; the SIP proposes federally enforceable emission limits for Naughton Unit 3 to fire on natural gas. The EPA issued its proposed approval of WDEQ's SIP revision on November 7, 2018, seeking public comments on the proposal.

On February 4, 2019, PacifiCorp filed a notification to the WDEQ that Naughton Unit 3 had ceased coal combustion; PacifiCorp designated Naughton Unit 3 as "temporarily 'mothballed' while awaiting final federal action" from the EPA on approval of the WDEQ SIP. PacifiCorp clarified in its notification that Naughton Unit 3 remained capable of generating 35 MW when fueled on natural gas, and that the unit could be considered effectively converted following EPA approval of the Wyoming SIP.

On March 21, 2019, the EPA published its approval of the Naughton Unit 3 conversion to natural gas and incorporated by reference the natural gas emission limits from Wyoming state air permits. PacifiCorp submitted a notification to WDEQ on May 24, 2019, for initial startup of Naughton Unit 3 on natural gas and commencement of construction for additional upgrades supporting the full conversion to 247 MW. PacifiCorp removed Naughton Unit 3 from designation as 'temporarily mothballed' and committed to completion of all construction relating to natural gas conversion by June 24, 2021.

PacifiCorp filed a notification with WDEQ on July 3, 2019, that Naughton Unit 3 was first fired (initial start-up after being temporarily mothballed) on natural gas on July 1, 2019.

Project activities to date in support of the increase in unit capacity to 247 MW are limited to design engineering and procurement of materials, no physical upgrades have been made as of yet as the Company is awaiting material deliveries to initiate construction. The project is expected to be completed by mid-2020.

Q. What is the cost to complete the full conversion of Naughton Unit 3 to a 247 MW natural gas fired generation resource?

A. The cost of the Naughton Unit 3 gas conversion to 247 MW included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on an Oregon-allocated basis.

Q. Does the Naughton Unit 3 gas conversion to a 247 MW natural gas fired generation resource provide customer benefits?

A. Yes. As discussed in the testimony from Mr. Link, full conversion of Naughton Unit 3 to a 247 MW gas fueled resource is projected to provide $18.3 million in savings for customers as analyzed in the 2019 IRP against early retirement of the unit. As such, the 2019 IRP Preferred Portfolio included Naughton Unit 3 gas conversion as a generation resource available to serve customers going forward.

VIII. CONCLUSION AND RECOMMENDATION

Q. Please summarize your testimony.

A. The Company prudently managed the analysis, implementation, and costs of the Energy Vision 2020 Wind Projects and the Pryor Mountain Wind Project which provide benefits to Oregon customers. These projects should be approved as prudent expenditures.

In addition, the Company prudently managed the analysis, implementation, and costs of the Jim Bridger Units 3-4 SCR projects. The projects were analyzed and managed in accordance with the Company's environmental compliance obligations, the Wyoming Public Service Commission Order granting a CPCN for the projects, the Utah Public Service Commission Order granting Resource Decision Pre-approval for the projects, and the Company's IRP processes. The Company completed the Jim Bridger Units 3-4 projects on time to meet all environmental compliance deadlines and performance requirements under budget, further supporting the prudence of the projects.

The Company prudently managed the analysis, implementation, and costs of the Hunter Unit 1 LNB and baghouse projects. The projects were analyzed and managed in accordance with the Company's environmental compliance obligations and the Company's IRP processes. The Company completed the Hunter Unit 1 projects on time to meet all environmental compliance deadlines and performance requirements under budget, further supporting the prudence of the projects.

The Company also prudently managed the analysis and appropriately exercised its rights under the Participation Agreement with respect to the Craig Unit 2

SCR project. The project was completed on time to meet all environmental compliance deadlines and performance requirements, and was administered by the plant Operating Agent, and supported by a majority vote of the unit's remaining joint owners, in accordance with Participation Agreement terms and conditions.

The Company's support of the Hayden Units 1-2 SCR installations included in this case has been administered pursuant to applicable law and the Partnership Agreement applicable to those Units.

These environmental compliance projects have allowed the retrofitted facilities to continue to operate as low-cost generation resources for the benefit of PacifiCorp's customers.

Finally, the Naughton Unit 3 natural gas conversion to 247 MW has been prudently analyze and implemented. The natural gas conversion project is *de minimis* in scope and facilitates operation of a significant generation resource during periods of peak loads across PacifiCorp's system for the benefit of customers.

Based on these conclusions, I recommend that the Commission approve each of the projects described in my testimony for inclusion in rates.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 374
Exhibit PAC/801
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

Energy Vision 2020 Wind Capital Cost Comparison

February 2020

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

Docket No. UE 374
Exhibit PAC/802
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

Site Plan Ekola Flats

February 2020

LEGEND

	TURBINES
	VESTAS 4.3 MW
	GE 2.3 MW
	SUBSTATION BREAKERS
	JUNCTION BOXES
	FEEDER 11
	FEEDER 12
	FEEDER 13
	FEEDER 14
	FEEDER 15
	FEEDER 21
	FEEDER 22
	FEEDER 23
	FEEDER 24
	FEEDER 25
	FIBER
	BORE
	MET TOWER
	MET TOWER CABLE
	Wetlands_Major_20170802
	Wetlands_Minor_20170802
	EkolaFlats_WW_RoadCL_20190612
	EkolaFlats_WW_RoadCL_MET_20190612
	EkolaFlats_WW_RoadCL_TwoTrack_20190612
	Ekola_T-Line_20180515
	Ekola_Flats_Pipelines_Identified_Topo_SiteVisit
	SUBSTATION
	EkolaFlats_WW_SurveyCorridorFinal_20190517
	EkolaFlats_Field_Delineated_Wetlands_20190517
	EkolaFlats_Cultural_Sites_to_Avoid_20190517
	BLM_Carbon
	O&M BUILDING
	OBSERVATION TOWER
	Observation Tower Cable
	GROUSE

NOTES:
1. THIS DRAWING'S SCOPE IS DEFINING THE COLLECTION CABLE ROUTING REQUIREMENTS. ADDITIONAL SCOPES SHOWN FOR COORDINATION ONLY AND SHALL NOT BE USED TO CONSTRUCT FROM. REFERENCE APPROPRIATE SCOPE CONSTRUCTION DOCUMENTS FOR REQUIREMENTS. FOR EXAMPLE, REFERENCE CIVIL CONSTRUCTION PLANS FOR PROJECT CIVIL REQUIREMENTS, AND REFERENCE T-LINE CONSTRUCTION PLANS FOR PROJECT T-LINE REQUIREMENTS.
2. PRIOR TO CONSTRUCTION VERIFY ALL EXISTING INFRASTRUCTURE LOCATIONS WITH ONE-CALL AND GPS LOCATES.
3. REFERENCE 116196-CL-310.01 SERIES FOR FEEDER ROUTING DIAGRAMS.

PRELIMINARY
NOT FOR CONSTRUCTION

N
0 1 2
Miles

MORTENSON ENGINEERING
PROJECT NUMBER ENG00026
Mortenson
700 MEADOW LANE NORTH
MINNEAPOLIS, MN 55422
PHONE: (763) 522-2100
FAX: (763) 287-5163

SAP#
PL# 111101
DATE 09/28/2018
ENG SL DES EF
DR MH CH MF
APPROVAL

EKOLA FLATS
COLLECTION SYSTEM
OVERALL SITEPLAN

PACIFICORP
WIND

SCALE: NONE
SHEET
116196-CL-300.01
REV. D

No.	DATE	REVISION	BY	CHK	APP
A	10/05/18	30% DESIGN REVIEW	MH	MF	SL
B	12/21/18	60% DESIGN REVIEW	JT	MF	SL
C	03/26/19	75% DESIGN REVIEW	JT	MF	SL
D	06/28/19	90% DESIGN REVIEW	JT	MF	SL

DRAWING No.	REFERENCE DRAWINGS	DRAWING No.	REFERENCE DRAWINGS

FILE LOCATION:D:\vault\Designs\ENG00026 EKOLA\116196-CL-300.01 SAVED BY:(JTEMPLE) 6/26/2019 1:21 PM PLOTTED BY:(JEN TEMPLE) 6/26/2019 1:25 PM

REDACTED
Docket No. UE 374
Exhibit PAC/803
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

Ekola Flats Assessment and Wind Resource and Energy Production Estimate

February 2020

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

REDACTED
Docket No. UE 374
Exhibit PAC/804
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

Ekola Flats Project Schedule

February 2020

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Docket No. UE 374
Exhibit PAC/805
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

Large Generator Interconnection Agreement Ekola Flats

February 2020

STANDARD LARGE GENERATOR

INTERCONNECTION AGREEMENT (LGIA)
between
PACIFICORP
and
Ekola Flats Wind Energy LLC
CARBON COUNTY 1 - Q706

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STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this 27th day of November, 20 17 by and between Ekola Flats Wind Energy LLC, a Limited Liability Company organized and existing under the laws of the State of Delaware ("Interconnection Customer") with a Large Generating Facility), and PacifiCorp a corporation organized and existing under the laws of the State of Oregon ("Transmission Provider and/or Transmission Owner"). Interconnection Customer and Transmission Provider each may be referred to as a "Party" or collectively as the "Parties."

Recitals

WHEREAS, Transmission Provider operates the Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and,

WHEREAS, Interconnection Customer and Transmission Provider have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility with the Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (Tariff).

Article 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection System Impact Study.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or

Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not

include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission

Provider's Transmission System. The scope of the study is defined in Section 43 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System, the scope of which is described in Section 41 of the Standard Large Generator Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility

pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

NERC shall mean the North American Electric Reliability Council or its successor organization.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of

constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose.

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in the Transmission Provider's Tariff.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission Provider's Transmission System or on other delivery systems or other generating systems to which the Transmission Provider's Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC,

and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Large Generator Interconnection Agreement to the extent necessary.

Transmission Provider shall mean the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Variable Energy Resource shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Article 2. Effective Date, Term, and Termination

2.1 **Effective Date.** This LGIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this LGIA with FERC upon execution in accordance with Article 3.1, if required.

2.2 **Term of Agreement.** Subject to the provisions of Article 2.3, this LGIA shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as Interconnection Customer may request (Term to be specified in individual agreements) and shall be automatically renewed for each successive one-year period thereafter.

2.3 **Termination Procedures.**

2.3.1 **Written Notice.** This LGIA may be terminated by Interconnection Customer after giving Transmission Provider ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

2.3.2 **Default.** Either Party may terminate this LGIA in accordance with Article 17.

2.3.3 Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this LGIA, which notice has been accepted for filing by FERC.

2.4 **Termination Costs.** If a Party elects to terminate this Agreement pursuant to Article 2.3 above, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party, as of the date of the other Party's receipt of such notice of

termination, that are the responsibility of the Terminating Party under this LGIA. In the event of termination by a Party, the Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this LGIA, unless otherwise ordered or approved by FERC:

2.4.1 With respect to any portion of Transmission Provider's Interconnection Facilities that have not yet been constructed or installed, Transmission Provider shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Provider shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Provider for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Provider shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Provider to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this LGIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities

and equipment, and other expenses including any Network Upgrades for which Transmission Provider has incurred expenses and has not been reimbursed by Interconnection Customer.

2.4.2 Transmission Provider may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Provider shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this LGIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 **Disconnection.** Upon termination of this LGIA, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 **Survival.** This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this LGIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

Article 3. Regulatory Filings

3.1 **Filing**. Transmission Provider shall file this LGIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this LGIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

Article 4. Scope of Service

4.1 **Interconnection Product Options.** Interconnection Customer has selected the following (checked) type of Interconnection Service:

☐ 4.1.1 **Energy Resource Interconnection Service.**

4.1.1.1 **The Product**. Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interconnection Service, Transmission Provider shall construct facilities identified in Attachment A.

4.1.1.2 **Transmission Delivery Service Implications**. Under Energy

Resource Interconnection Service, Interconnection Customer will be eligible to inject power from the Large Generating Facility into and deliver power across the interconnecting Transmission Provider's Transmission System on an "as available" basis up to the amount of MWs identified in the applicable stability and steady state studies to the extent the upgrades initially required to qualify for Energy Resource Interconnection Service have been constructed. Where eligible to do so (e.g., PJM, ISO-NE, NYISO), Interconnection Customer may place a bid to sell into the market up to the maximum identified Large Generating Facility output, subject to any conditions specified in the interconnection service approval, and the Large Generating Facility will be dispatched to the extent Interconnection Customer's bid clears. In all other instances, no transmission delivery service from the Large Generating Facility is assured, but Interconnection Customer may obtain Point-to-Point Transmission Service, Network Integration Transmission Service, or be used for secondary network transmission service, pursuant to Transmission Provider's Tariff, up to the maximum output identified in the stability and steady state studies. In those instances, in order for Interconnection Customer to obtain the right to deliver or inject energy beyond the Large Generating Facility Point of Interconnection or to improve its ability to do so, transmission

delivery service must be obtained pursuant to the provisions of Transmission Provider's Tariff. The Interconnection Customer's ability to inject its Large Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of Transmission Provider's Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of firm Point-to-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

☐ 4.1.2 **Network Resource Interconnection Service.**

4.1.2.1 **The Product**. Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as all Network Resources. To the extent Interconnection Customer wants to receive Network Resource Interconnection Service, Transmission Provider shall construct the facilities identified in Attachment A to this LGIA.

4.1.2.2 **Transmission Delivery Service Implications**. Network Resource

Interconnection Service allows Interconnection Customer's Large Generating Facility to be designated by any Network Customer under the Tariff on Transmission Provider's Transmission System as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Large Generating Facility in the same manner as it accesses Network Resources. A Large Generating Facility receiving Network Resource Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Large Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Large Generating Facility has not been designated as a Network Resource by any load, it cannot be

required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or firm Point-to-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Large Generating Facility to any particular load on Transmission Provider's Transmission System without incurring congestion costs. In the event of transmission constraints on Transmission Provider's Transmission System, Interconnection Customer's Large Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that Interconnection Customer's Large Generating Facility be designated

as a Network Resource by a Network Service Customer under the Tariff or that Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does designate the Large Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interconnection Service, any future transmission service request for delivery from the Large Generating Facility within Transmission Provider's Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Large Generating Facility be undertaken, regardless of whether or not such Large Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Large Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Large Generating Facility outside

Transmission Provider's Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

4.2 **Provision of Service.** Transmission Provider shall provide Interconnection Service for the Large Generating Facility at the Point of Interconnection.

4.3 **Performance Standards.** Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is a Transmission Provider or Transmission Owner, then that Party shall amend the LGIA and submit the amendment to FERC for approval.

4.4 **No Transmission Delivery Service.** The execution of this LGIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

4.5 **Interconnection Customer Provided Services.** The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.5.1.

Interconnection Customer shall be paid for such services in accordance with Article 11.6.

Article 5. Interconnection Facilities Engineering, Procurement, and Construction

5.1 **Options.** Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either Standard Option or Alternate Option set forth below for

completion of Transmission Provider's Interconnection Facilities and Network Upgrades as set forth in Appendix A, Interconnection Facilities and Network Upgrades, and such dates and selected option shall be set forth in Appendix B, Milestones.

5.1.1 **Standard Option**. Transmission Provider shall design, procure, and construct Transmission Provider's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Provider shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Provider reasonably expects that it will not be able to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the specified dates, Transmission Provider shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 **Alternate Option**. If the dates designated by Interconnection Customer are acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities by the designated dates.

If Transmission Provider subsequently fails to complete Transmission Provider's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to

complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B, Milestones; Transmission Provider shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable RTO or ISO refuses to grant clearances to install equipment.

5.1.3 **Option to Build.** If the dates designated by Interconnection Customer are not acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. Transmission Provider and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 **Negotiated Option.** If Interconnection Customer elects not to exercise its option under Article 5.1.3, Option to Build, Interconnection Customer shall so notify Transmission Provider within thirty (30) Calendar Days, and the Parties shall in

good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades by Interconnection Customer) pursuant to which Transmission Provider is responsible for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, Transmission Provider shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Network Upgrades pursuant to 5.1.1, Standard Option.

5.2 **General Conditions Applicable to Option to Build.** If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Provider;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Provider shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider;

(5) at any time during construction, Transmission Provider shall have the right to gain unrestricted access to Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Provider, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider for claims arising from Interconnection Customer's construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) Interconnection Customer shall transfer control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Provider's Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Provider;

(10) Transmission Provider shall approve and accept for operation and maintenance Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information, and any other documents that are reasonably required by Transmission Provider to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

5.3 **Liquidated Damages.** The actual damages to Interconnection Customer, in the event Transmission Provider's Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Provider pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Provider to Interconnection Customer in the event that Transmission Provider does not complete any portion of Transmission Provider's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of Transmission Provider's Interconnection Facilities and Network

Upgrades, in the aggregate, for which Transmission Provider has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades for which Transmission Provider has assumed responsibility to design, procure, and construct. The foregoing payments will be made by Transmission Provider to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Transmission Provider's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for the Large Generating Facility's Trial Operation or to export power from the Large Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for Large Generating Facility's Trial Operation or to export power from the Large Generating Facility, but for Transmission Provider's delay; (2) Transmission Provider's failure to meet the specified dates is the result of the action or inaction of Interconnection Customer or any other Interconnection Customer who has entered into an LGIA with Transmission Provider or any cause beyond Transmission Provider's reasonable control or reasonable ability to cure; (3) the interconnection Customer has assumed responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 **Power System Stabilizers.** The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative. The requirements of this paragraph shall not apply to wind generators.

5.5 **Equipment Procurement.** If responsibility for construction of Transmission Provider's Interconnection Facilities or Network Upgrades is to be borne by Transmission Provider, then Transmission Provider shall commence design of Transmission Provider's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 Transmission Provider has completed the Facilities Study pursuant to the Facilities Study Agreement;

5.5.2 Transmission Provider has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.5.3 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.6 **Construction Commencement.** Transmission Provider shall commence construction of Transmission Provider's Interconnection Facilities and Network Upgrades for which it is responsible as soon as

practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Provider's Interconnection Facilities and Network Upgrades;

5.6.3 Transmission Provider has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.6.4 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.7 **Work Progress**. The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Either Party may, at any time, request a progress report from the other Party. If, at any time, Interconnection Customer determines that the completion of Transmission Provider's Interconnection Facilities will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider of such later date upon which the completion of Transmission Provider's Interconnection Facilities will be required.

5.8 **Information Exchange**. As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with Transmission Provider's Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 **Limited Operation.** If any of Transmission Provider's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Large Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Large Generating Facility and Interconnection Customer's Interconnection Facilities may operate prior to the completion of Transmission Provider's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. Transmission Provider shall permit Interconnection Customer to operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.10 **Interconnection Customer's Interconnection Facilities ('ICIF').** Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.10.1 **Interconnection Customer's Interconnection Facility Specifications.** Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Provider at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Provider shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's

submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 **Transmission Provider's Review.** Transmission Provider's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Provider, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider.

5.10.3 **ICIF Construction.** The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Large Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Large Generating Facility. The Interconnection Customer shall provide Transmission Provider specifications for the excitation system, automatic voltage regulator, Large

Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.11 **Transmission Provider's Interconnection Facilities Construction.** Transmission Provider's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Provider shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Provider's Interconnection Facilities [include appropriate drawings and relay diagrams].

Transmission Provider will obtain control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

5.12 **Access Rights.** Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to the other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the Transmission System; (ii) operate and maintain the Large Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed

from time to time, by the Granting Party and provided to the Access Party.

5.13 **Lands of Other Property Owners.** If any part of Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Provider or Transmission Owner, Transmission Provider or Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

5.14 **Permits.** Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

5.15 **Early Construction of Base Case Facilities.** Interconnection Customer may request Transmission Provider to construct, and Transmission Provider shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not

scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 **Suspension.** Interconnection Customer reserves the right, upon written notice to Transmission Provider, to suspend at any time all work by Transmission Provider associated with the construction and installation of Transmission Provider's Interconnection Facilities and/or Network Upgrades required under this LGIA with the condition that Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Provider's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Provider (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Provider cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Provider shall obtain Interconnection Customer's authorization to do so.

Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Transmission Provider required under this LGIA pursuant to this Article 5.16, and has not requested Transmission Provider to recommence the work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Transmission Provider, if no effective date is specified.

5.17 **Taxes.**

5.17.1 **Interconnection Customer Payments Not Taxable.** The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Provider for the installation of Transmission Provider's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 **Representations and Covenants.** In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to Transmission Provider for Transmission Provider's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of Transmission Provider's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to

IRS requirements for non-taxable treatment.

At Transmission Provider's request, Interconnection Customer shall provide Transmission Provider with a report from an independent engineer confirming its representation in clause (iii), above. Transmission Provider represents and covenants that the cost of Transmission Provider's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 **Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon the Transmission Provider.** Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Transmission Provider from the cost consequences of any current tax liability imposed against Transmission Provider as the result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Transmission Provider.

Transmission Provider shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this LGIA unless (i) Transmission Provider has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Transmission Provider should be reported as income subject to taxation or (ii) any Governmental Authority directs Transmission Provider to report payments or property as income subject to taxation; provided, however, that Transmission Provider may require Interconnection Customer to provide security for

Interconnection Facilities, in a form reasonably acceptable to Transmission Provider (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Transmission Provider for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Transmission Provider of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by Transmission Provider upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 **Tax Gross-Up Amount.** Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Interconnection Customer will pay Transmission Provider, in addition to the amount paid for the Interconnection Facilities and Network Upgrades, an amount equal to (1) the current taxes imposed on Transmission Provider ("Current Taxes") on the excess of (a) the gross income realized by Transmission Provider as a result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount")

over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit Transmission Provider to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Transmission Provider's composite federal and state tax rates at the time the payments or property transfers are received and Transmission Provider will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Transmission Provider's anticipated tax depreciation deductions as a result of such payments or property transfers by Transmission Provider's current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount - Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.17.5 **Private Letter Ruling or Change or Clarification of Law.** At Interconnection Customer's request and expense, Transmission Provider shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Transmission

Provider under this LGIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Transmission Provider and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Transmission Provider shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Transmission Provider shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 **Subsequent Taxable Events.** If, within 10 years from the date on which the relevant Transmission Provider's Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this LGIA terminates and Transmission Provider retains ownership of the Interconnection Facilities and Network Upgrades, Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Transmission Provider, calculated using the methodology described

in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 **Contests.** In the event any Governmental Authority determines that Transmission Provider's receipt of payments or property constitutes income that is subject to taxation, Transmission Provider shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Transmission Provider may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Transmission Provider reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Transmission Provider shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Transmission Provider may agree to a settlement either with Interconnection

Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Transmission Provider, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Transmission Provider for the tax at issue in the contest.

5.17.8 **Refund.** In the event that (a) a private letter ruling is issued to Transmission Provider which holds that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Transmission Provider in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not taxable to Transmission Provider, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Transmission Provider are not subject to federal income

tax, or (d) if Transmission Provider receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Transmission Provider pursuant to this LGIA, Transmission Provider shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by Interconnection Customer to Transmission Provider for such taxes which Transmission Provider did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Transmission Provider refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Transmission Provider, any refund or credit Transmission Provider receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to Transmission Provider for such overpayment of taxes (including any reduction in interest otherwise payable by Transmission Provider to any Governmental Authority resulting

from an offset or credit); provided, however, that Transmission Provider will remit such amount promptly to Interconnection Customer only after and to the extent that Transmission Provider has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to Transmission Provider's Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 **Taxes Other Than Income Taxes.** Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Provider for which Interconnection Customer may be required to reimburse Transmission Provider under the terms of this LGIA. Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Transmission Provider shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Transmission Provider for such

taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Provider.

5.17.10 **Transmission Owners Who Are Not Transmission Providers.** If Transmission Provider is not the same entity as the Transmission Owner, then (i) all references in this Article 5.17 to Transmission Provider shall be deemed also to refer to and to include the Transmission Owner, as appropriate, and (ii) this LGIA shall not become effective until such Transmission Owner shall have agreed in writing to assume all of the duties and obligations of Transmission Provider under this Article 5.17 of this LGIA.

5.18 **Tax Status.** Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this LGIA is intended to adversely affect any Transmission Provider's tax exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 **Modification.**

5.19.1 **General.** Either Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, that Party shall provide to the other Party sufficient information regarding such modification so that the other Party may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall

include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Large Generating Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Provider shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Provider's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 **Standards.** Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 **Modification Costs.** Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Provider makes to Transmission Provider's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Provider's Interconnection Facilities or the Transmission System, or to provide

transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

Article 6. Testing and Inspection

6.1 **Pre-Commercial Operation Date Testing and Modifications.** Prior to the Commercial Operation Date, Transmission Provider shall test Transmission Provider's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Large Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Large Generating Facility only if it has arranged for the delivery of such test energy.

6.2 **Post-Commercial Operation Date Testing and Modifications.** Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Large Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 **Right to Observe Testing**. Each Party shall notify the other Party in advance of its performance of tests of its Interconnection Facilities. The other Party has the right, at its own expense, to observe such testing.

6.4 **Right to Inspect**. Each Party shall have the right, but shall have no obligation to: (i) observe the other Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of the other Party's System Protection Facilities and other protective equipment; and (iii) review the other Party's maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. A Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Party. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this LGIA.

Article 7. Metering

7.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Provider shall install Metering Equipment at the Point of Interconnection prior to any operation of the Large Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Large Generating Facility shall be measured at or, at Transmission Provider's option, compensated to, the Point of Interconnection. Transmission Provider shall provide metering quantities, in analog and/or digital form, to Interconnection Customer upon request. Interconnection Customer shall bear all

reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 **Check Meters**. Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Provider's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Provider or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 **Standards**. Transmission Provider shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

7.4 **Testing of Metering Equipment**. Transmission Provider shall inspect and test all Transmission Provider-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Transmission Provider shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than every two (2) years. Transmission Provider shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Provider's failure to maintain, then Transmission Provider shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission

Provider shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

7.5 **Metering Data.** At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Provider and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Large Generating Facility to the Point of Interconnection.

Article 8. Communications

8.1 **Interconnection Customer Obligations.** Interconnection Customer shall maintain satisfactory operating communications with Transmission Provider's Transmission System dispatcher or representative designated by Transmission Provider. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Large Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Provider as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Large Generating Facility to the location(s) specified by Transmission Provider. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation,

scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 **Remote Terminal Unit**. Prior to the Initial Synchronization Date of the Large Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Provider at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Provider through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Provider. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Provider.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 **No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4 **Provision of Data from a Variable Energy Resource.** The Interconnection Customer whose Generating Facility is a Variable Energy Resource shall provide meteorological and forced outage data to the Transmission Provider to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The Interconnection Customer with a Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, wind

speed, wind direction, and atmospheric pressure. The Interconnection Customer with a Variable Energy Resource having solar as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission Provider and Interconnection Customer whose Generating Facility is a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility is a Variable Energy Resource also shall submit data to the Transmission Provider regarding all forced outages to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Such requirements for meteorological and forced outage data are set forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

Article 9. Operations

9.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 **Control Area Notification.** At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider in

writing of the Control Area in which the Large Generating Facility will be located. If Interconnection Customer elects to locate the Large Generating Facility in a Control Area other than the Control Area in which the Large Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Control Area.

9.3 **Transmission Provider Obligations.** Transmission Provider shall cause the Transmission System and Transmission Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA. Transmission Provider may provide operating instructions to Interconnection Customer consistent with this LGIA and Transmission Provider's operating protocols and procedures as they may change from time to time. Transmission Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

9.4 **Interconnection Customer Obligations.** Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA. Interconnection Customer shall operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this LGIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Either Party may request that the other Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this LGIA.

9.5 **Start-Up and Synchronization.** Consistent with the Parties' mutually acceptable procedures, Interconnection Customer is responsible for the proper synchronization of the Large Generating Facility to Transmission Provider's Transmission System.

9.6 **Reactive Power.**

9.6.1 **Power Factor Design Criteria.** Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis. The requirements of this paragraph shall not apply to wind generators.

9.6.1.1 **Synchronous Generation** Interconnection Customer shall design the Large Generating Facility to maintain a composite power deliver at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all synchronous generators in the Control Area on a comparable basis.

9.6.1.2 **Non-Synchronous Generation** Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all non-synchronous generators in the Control Area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of the Final Rule establishing this requirement (Order No. 827).

9.6.2 **Voltage Schedules.** Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Transmission Provider shall require Interconnection Customer to operate the Large Generating Facility to produce or absorb reactive power within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Provider's voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. Transmission Provider shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance,

and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Large Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the System Operator.

9.6.2.1 Governors and Regulators. Whenever the Large Generating Facility is operated in parallel with the Transmission System and the speed governors (if installed on the generating unit pursuant to Good Utility Practice) and voltage regulators are capable of operation, Interconnection Customer shall operate the Large Generating Facility with its speed governors and voltage regulators in automatic operation. If the Large Generating Facility's speed governors and voltage regulators are not capable of such automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative, and ensure that such Large Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Large Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Control Area on a comparable basis.

9.6.3 **Payment for Reactive Power.** Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Large Generating Facility when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1, provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed.

9.7 **Outages and Interruptions.**

9.7.1 **Outages.**

9.7.1.1 **Outage Authority and Coordination.** Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an

Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to the Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Party of such removal.

9.7.1.2 **Outage Schedules.** Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Large Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission

Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

9.7.1.3 **Outage Restoration**. If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects the other Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Party, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

9.7.2 **Interruption of Service**. If required by Good Utility Practice to do so, Transmission Provider may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Provider;

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Large Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 **Under-Frequency and Over Frequency Conditions.** The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability of the Transmission System. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

9.7.4 **System Protection and Other Control Requirements.**

9.7.4.1 **System Protection Facilities.** Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Provider's Interconnection Facilities or the Transmission System as a result of the interconnection of the Large Generating Facility and Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

9.7.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 **Requirements for Protection.** In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Provider's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Large Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Large Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Large Generating Facility.

9.7.6 **Power Quality.** Neither Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

9.8 **Switching and Tagging Rules.** Each Party shall provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in

obtaining clearances for work or for switching operations on equipment.

9.9 **Use of Interconnection Facilities by Third Parties.**

9.9.1 **Purpose of Interconnection Facilities.** Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Transmission System and shall be used for no other purpose.

9.9.2 **Third Party Users.** If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Provider's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.10 **Disturbance Analysis Data Exchange.** The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or Transmission Provider's Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

Article 10. Maintenance

10.1 **Transmission Provider Obligations.** Transmission Provider shall maintain the Transmission System and Transmission Provider's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.2 **Interconnection Customer Obligations.** Interconnection Customer shall maintain the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.3 **Coordination.** The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Large Generating Facility and the Interconnection Facilities.

10.4 **Secondary Systems.** Each Party shall cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Party. Each Party shall provide advance notice to the other Party before undertaking any work on such circuits, especially on electrical circuits involving circuit

breaker trip and close contacts, current transformers, or potential transformers.

10.5 **Operating and Maintenance Expenses.** Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Provider's Interconnection Facilities.

Article 11. Performance Obligation

11.1 **Interconnection Customer Interconnection Facilities.** Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

11.2 **Transmission Provider's Interconnection Facilities.** Transmission Provider or Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Provider's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

11.3 **Network Upgrades and Distribution Upgrades.** Transmission Provider or Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades. The Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless Transmission Provider or Transmission Owner elects to fund the capital for the Network Upgrades, they shall

be solely funded by Interconnection Customer. In the event that Transmission Provider must change the voltage levels of a discrete portion of the Transmission System to which the Interconnection Customer is connected, Transmission Provider shall give reasonable notice of such change and the Interconnection Customer shall be solely responsible for all costs related to upgrades or modifications to Interconnection Customer's Interconnection Facilities resulting from Transmission Provider's increase in the voltage levels of the Transmission System, in order to remain interconnected with the Transmission System at the new operating voltage. To the extent that the modifications necessary to upgrade Interconnection Facilities qualify as Network Upgrades, Transmission Provider shall be solely responsible for the expense of such modifications or upgrades.

11.4 Transmission Credits.

11.4.1 **Repayment of Amounts Advanced for Network Upgrades**. Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to Transmission Provider and Affected System Operator, if any, for the Network Upgrades, including any tax gross-up or other tax-related payments associated with Network Upgrades, and not refunded to Interconnection Customer pursuant to Article 5.17.8 or otherwise, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Large Generating Facility. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC=s regulations at 18 C.F.R. § 35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph.

Interconnection Customer may assign such repayment rights to any person.

Notwithstanding the foregoing, Interconnection Customer, Transmission Provider, and Affected System Operator may adopt any alternative payment schedule that is mutually agreeable so long as Transmission Provider and Affected System Operator take one of the following actions no later than five years from the Commercial Operation Date: (1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or (2) declare in writing that Transmission Provider or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full reimbursement shall not extend beyond twenty (20) years from the Commercial Operation Date.

If the Large Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, Transmission Provider and Affected System Operator shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the Generating Facility, if different, is responsible for identifying the entity to which reimbursement must be made.

11.4.2 **Special Provisions for Affected Systems.** Unless Transmission Provider provides, under the LGIA, for the repayment of

amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

11.4.3 Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Large Generating Facility.

11.5 **Provision of Security**. At least thirty (30) Calendar Days prior to the commencement of the first of the following to occur: design, procurement, installation, or construction of a discrete portion of a Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and shall be

reduced on a dollar-for-dollar basis for payments made to Transmission Provider for these purposes.

In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must indicate that it would only expire upon final payment made to Transmission Provider to cover all relevant costs for designing, procuring, installing, and constructing the applicable portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which the letter of credit was provided.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must indicate that it would only expire upon final payment made to Transmission Provider to cover all relevant costs for designing, procuring, installing, and constructing the applicable portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which the surety bond was provided.

11.6 **Interconnection Customer Compensation.** If Transmission Provider requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this LGIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to an RTO or ISO FERC-approved rate schedule. Interconnection Customer

shall serve Transmission Provider or RTO or ISO with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this LGIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

11.6.1 **Interconnection Customer Compensation for Actions During Emergency Condition.** Transmission Provider or RTO or ISO shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.6.

Article 12. Invoice

12.1 **General.** Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this LGIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 **Final Invoice.** Within six months after completion of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades, Transmission Provider shall provide an invoice of the final cost of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades and shall set forth such costs in sufficient

detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 **Payment**. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this LGIA.

12.4 **Disputes**. In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide Interconnection Service under this LGIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii).

Article 13. Emergencies

13.1 **Definition**. "Emergency Condition" shall mean a condition or situation: (i) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (ii) that, in the case

of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, Transmission Provider's Interconnection Facilities or the Transmission Systems of others to which the Transmission System is directly connected; or (iii) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Large Generating Facility or Interconnection Customer's Interconnection Facilities' System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by this LGIA to possess black start capability.

13.2 **Obligations**. Each Party shall comply with the Emergency Condition procedures of the applicable ISO/RTO, NERC, the Applicable Reliability Council, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

13.3 **Notice.** Transmission Provider shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Provider's Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Transmission Provider promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Provider's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Provider's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall

be followed as soon as practicable with written notice.

13.4 **Immediate Action.** Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Provider, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or otherwise regarding the Transmission System.

13.5 **Transmission Provider Authority.**

13.5.1 **General.** Transmission Provider may take whatever actions or inactions with regard to the Transmission System or Transmission Provider's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Provider's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a

reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Large Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 **Reduction and Disconnection.** Transmission Provider may reduce Interconnection Service or disconnect the Large Generating Facility or Interconnection Customer's Interconnection Facilities, when such, reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of Transmission Provider pursuant to Transmission Provider's Tariff. When Transmission Provider can schedule the reduction or disconnection in advance, Transmission Provider shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection Customer and Transmission Provider. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities, and the Transmission System to their normal

operating state as soon as practicable consistent with Good Utility Practice.

13.6 **Interconnection Customer Authority.** Consistent with Good Utility Practice and the LGIA and the LGIP, Interconnection Customer may take actions or inactions with regard to the Large Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Provider's Interconnection Facilities. Transmission Provider shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.7 **Limited Liability.** Except as otherwise provided in Article 11.6.1 of this LGIA, neither Party shall be liable to the other for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

Article 14. Regulatory Requirements and Governing Law

14.1 **Regulatory Requirements.** Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this LGIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act, the Public Utility Holding Company

Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978.

14.2 **Governing Law.**

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

Article 15. Notices.

15.1 **General.** Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Either Party may change the notice information in this LGIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 **Billings and Payments.** Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 **Alternative Forms of Notice.** Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given

in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 **Operations and Maintenance Notice.** Each Party shall notify the other Party in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

Article 16. Force Majeure

16.1 **Force Majeure.**

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

Article 17. Default

17.1 Default

17.1.1 **General.** No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act of omission of the other Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 **Right to Terminate.** If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this LGIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this LGIA.

Article 18. Indemnity, Consequential Damages and Insurance

18.1 **Indemnity**. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this LGIA on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnified Party.

18.1.1 **Indemnified Person**. If an Indemnified Person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such Indemnified Person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 **Indemnifying Party**. If an Indemnifying Party is obligated to indemnify and hold any Indemnified Person harmless under this Article 18, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

18.1.3 **Indemnity Procedures**. Promptly after receipt by an Indemnified Person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Person shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the Indemnifying Party and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the Indemnifying Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses.

The Indemnified Person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the Indemnified Person and the Indemnifying Party, in such event the Indemnifying Party shall pay the reasonable expenses of the Indemnified

Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be reasonably withheld, conditioned or delayed.

18.2 **Consequential Damages.** Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 **Insurance.** Each party shall, at its own expense, maintain in force throughout the period of this LGIA, and until released by the other Party, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this LGIA.

18.3.9 Within ten (10) days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, each Party shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

Article 19. Assignment

19.1 **Assignment**. This LGIA may be assigned by either Party only with the written consent of the other; provided that either Party may assign this LGIA without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this LGIA; and provided further that Interconnection Customer shall have the right to assign this LGIA, without the consent of Transmission Provider, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that Interconnection Customer will promptly notify Transmission Provider of any such assignment. Any financing arrangement entered into by Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured Party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider of the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

Article 20. Severability

20.1 **Severability**. If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Provider) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

Article 21. Comparability

21.1 **Comparability.** The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

Article 22. Confidentiality

22.1 **Confidentiality.** Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 **Term.** During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 **Scope.** Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of the LGIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

22.1.3 **Release of Confidential Information.** Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential

Information in contravention of this Article 22.

22.1.4 **Rights.** Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 **No Warranties.** By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 **Standard of Care.** Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this LGIA or its regulatory requirements.

22.1.7 **Order of Disclosure.** If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such

request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this LGIA.

Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 **Termination of Agreement.** Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

22.1.9 **Remedies.** The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants

contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 **Disclosure to FERC, its Staff, or a State.** Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 CFR section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this LGIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party

claims is competitively sensitive, commercial or financial information under this LGIA ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

Article 23. Environmental Releases

23.1 Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the

Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

Article 24. Information Requirements

24.1 **Information Acquisition.** Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 **Information Submission by Transmission Provider.** The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 **Updated Information Submission by Interconnection Customer.** The updated information submission by Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Trial Operation. Interconnection Customer shall submit a completed copy of the Large Generating Facility data

requirements contained in Appendix 1 to the LGIP. It shall also include any additional information provided to Transmission Provider for the Feasibility and Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study Agreement between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on Transmission Provider Transmission System based on the actual data submitted pursuant to this Article 24.3. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

24.4 **Information Supplementation.** Prior to the Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Large Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Large Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Large Generating Facility to verify proper operation of the Large Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Large Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent change in Large Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the

responses of Large Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Large Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Large Generating Facility terminal or field voltages is provided. Large Generating Facility testing shall be conducted and results provided to Transmission Provider for each individual generating unit in a station.

Subsequent to the Operation Date, Interconnection Customer shall provide Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Provider shall provide Interconnection Customer any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Provider-owned substation that may affect Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

Article 25. Information Access and Audit Rights

25.1 **Information Access**. Each Party (the "disclosing Party") shall make available to the other Party information that is in the possession of the disclosing Party and is necessary in order for the other Party to: (i) verify the costs incurred by the disclosing Party for which the other Party is responsible under this LGIA; and (ii) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA.

25.2 **Reporting of Non-Force Majeure Events**. Each Party (the "notifying Party") shall notify the other Party when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The

Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this LGIA.

25.3 **Audit Rights.** Subject to the requirements of confidentiality under Article 22 of this LGIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party, to audit at its own expense the other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this LGIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this LGIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 **Audit Rights Periods.**

25.4.1 **Audit Rights Period for Construction-Related Accounts and Records.** Accounts and records related to the design, engineering, procurement, and construction of Transmission Provider's Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission

Provider's issuance of a final invoice in accordance with Article 12.2.

25.4.2 **Audit Rights Period for All Other Accounts and Records.** Accounts and records related to either Party's performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

25.5 **Audit Results.** If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

Article 26. Subcontractors

26.1 **General.** Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

26.2 **Responsibility of Principal.** The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Provider be liable for the actions or

inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 **No Limitation by Insurance**. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

Article 27. Disputes

27.1 **Submission.** In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 **External Arbitration Procedures**. Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third

arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail.

27.3 Arbitration Decisions. Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

27.4 Costs. Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

Article 28. Representations, Warranties, and Covenants

28.1 **General.** Each Party makes the following representations, warranties and covenants:

28.1.1 **Good Standing.** Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 **Authority.** Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 **No Conflict.** The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any

judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 **Consent and Approval.** Such Party has sought or obtained, or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

Article 29. Joint Operating Committee

29.1 Joint Operating Committee. Except in the case of ISOs and RTOs, Transmission Provider shall constitute a Joint Operating Committee to coordinate operating and technical considerations of Interconnection Service. At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Interconnection Customer shall notify Transmission Provider of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of either Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this LGIA. Each Party shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

29.1.1 Establish data requirements and operating record requirements.

29.1.2 Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

29.1.3 Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Provider's and Interconnection Customer's facilities at the Point of Interconnection.

29.1.4 Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Large Generating Facility and other facilities that impact the normal operation of the interconnection of the Large Generating Facility to the Transmission System.

29.1.5 Ensure that information is being provided by each Party regarding equipment availability.

29.1.6 Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

Article 30. Miscellaneous

30.1 **Binding Effect.** This LGIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 **Conflicts.** In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties.

30.3 **Rules of Interpretation.** This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix to this LGIA, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 **Entire Agreement.** This LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this LGIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this LGIA.

30.5 **No Third Party Beneficiaries.** This LGIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 **Waiver.** The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party. Any waiver at any time by either Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this LGIA. Termination or Default of this LGIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 **Headings.** The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

30.8 **Multiple Counterparts.** This LGIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 **Amendment.** The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by the Parties.

30.10 **Modification by the Parties.** The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. Transmission Provider shall have the right to make a unilateral filing with FERC to modify this LGIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

IN WITNESS WHEREOF, the Parties have executed this LGIA in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

PACIFICORP

By:

Title: VP, Transmission

Date: 11/27/17

Ekola Flats Wind Energy LLC (Q706)

By:

Title: Michael Baird
Senior Vice President

Date:

LEGAL REVIEWED

Appendix A to LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

1. **Interconnection Facilities:**

   (a) **Interconnection Customer's Interconnection Facilities:** Two (2) circuit breakers (one per step up transformer) connected to approximately seven (7) miles of generator tie line for the Q706 collector substation to the Point of Interconnection (Aeolus substation). One circuit breaker will be located approximately adjacent to Aeolus substation. Please see Exhibit 1 to Attachment A.

   (b) **Transmission Provider's Interconnection Facilities:** Two (2) production meters located at the high side of the step up transformers at the Q706 collector substation, one (1) interchange meter at the Point of Change of Ownership, relay and grounding upgrades required for the new line position, and one new line position (dead end structure, disconnect switch, metering structure) located at the Point of Interconnection (Aeolus substation). Customer will also install fiber optic cable (to be owned by Transmission Provider) on generation tie line. Please see Exhibit 1 to Attachment A.

2. **Network Upgrades:**

   (a) **Stand Alone Network Upgrades:** None

   (b) **Other Network Upgrades:** None

3. **Distribution Upgrades:** None

4. **Point of Interconnection ("POI"):** The point at which Transmission Provider Interconnection Facilities connect to the substation bus at Aeolus substation (see Exhibit 1 to Appendix A).

5. **Point of Change of Ownership:** The point at which Interconnection Customer and Transmission Provider

Interconnection Facilities meet (see Exhibit 1 to Appendix A).

6. **One-Line Diagram:** is attached to this agreement as Exhibit 1 to Appendix A.

7. **Contingent Facilities:** The Point of Interconnection for this project is Aeolus 230 kV substation which is planned to be constructed as part of the Transmission Provider Gateway West D2 project. Aeolus substation, as well as the Gateway West Segment D2 500 kV transmission line (Aeolus-Anticline) are contingent for this project and must be in service prior to approval of generation activities for this project. If the schedule for completion of Aeolus substation or Gateway West Segment D2 are modified then the schedule for this project will need to be modified to align with the new completion date.

8. **Tax Gross-Up Amount:** There is no tax gross-up anticipated for the Direct Assignment Facilities and Transmission Provider's Interconnection Facilities installed under this Agreement. The estimated tax liability, in the event that Transmission Provider is assessed a tax liability for these facilities, is calculated pursuant to the formula in Article 5.17.4 of this Agreement as follows:

Current Tax Rate - 37.95%
Gross Income Amount - $2,760,000
Present Value of Tax Depreciation - $561,267

Estimated Tax Liability - 37.95% x ($2,760,000-$561,267)/(1-37.95%) = $1,842,341

The above tax liability calculation is an example only. In the event Transmission Provider is assessed a tax liability for the Direct Assignment Facilities and Transmission Provider's Interconnection Facilities installed pursuant to this LGIA, the actual tax liability will be calculated at that time based upon the actual values then obtained for current tax rate, gross income amount and present value of the tax depreciation.

Appendix B To LGIA

Milestones

Milestone/Date	Party
Execute Interconnection Agreement November 15, 2017	Interconnection Customer
Provision of Financial Security ($550,000) July 27, 2018	Interconnection Customer
Final Issue for Construction Design Package Provided August 31, 2018	Interconnection Customer
*Engineering & Procurement Commences November 6, 2018	Transmission Provider
**Energy Imbalance Market Modeling Data Submittal January 9, 2019	Interconnection Customer
Engineering Design Complete March 6, 2019	Transmission Provider
Property/Permits/ROW Procured April 10, 2019	Interconnection Customer
Construction Begins August 7, 2019	Transmission Provider
Facilities Receive Backfeed Power October 1, 2020	Interconnection Customer
***Initial Synchronization and Customer Generation Testing October 15, 2020	Interconnection
Commercial Operation November 1, 2020	Interconnection Customer

*As applicable and determined by the Transmission Provider, within 60 days of the Interconnection Customer's authorization for the Transmission Provider to begin engineering, the Interconnection Customer shall provide a detailed short circuit model of its generation system. This model must be constructed using the ASPEN OneLine short circuit simulation program and contain all individual electrical components of the Interconnection Customer's generation system.

**Any design modifications to the Interconnection Customer's Generating Facility after this date requiring updates to the Transmission Provider's network model will result in a minimum of 3 months added to all future milestones including Commercial Operation.

***The Transmission Provider's Gateway West Segment D2 500 kV transmission line (Aeolus-Anticline) must be in service prior to commencement of any generation activities.

Term of Agreement: In accordance with LGIA Article 2.2, the Parties agree that the term of the LGIA shall be ten (10) years from the Effective Date and shall be automatically renewed for each successive one-year period thereafter.

Construction Option: The Network Upgrades, Direct Assignment Facilities and Transmission Provider Interconnection Facilities will be designed, procured and constructed by the Transmission Provider in accordance with the Standard Option outlined in Article 5.1.1 of this Agreement. The Network Upgrades, Direct Assignment Facilities and Transmission Provider Interconnection Facilities shall be constructed in accordance with the Scope of Work attached to this LGIA as Exhibit 1 to Appendix B. The Network Upgrades, Direct Assignment Facilities and Transmission Provider's Interconnection Facilities shall be designed, procured and constructed in a timely manner to support the Milestone Dates stated above.

Estimated Project Cost

Network Upgrades:	$0
Direct Assigned:	$2,760,000
Total	$2,760,000

Appendix C To LGIA

Interconnection Details

Description of the Large Generating Facility: The Q0706 Large Generating Facility consists of one hundred twenty five (125) GE 2.0-116 2 MW turbines connected to ten (10) 34.5 kV strings for a total generation output of 250 MW as measured by nameplate. Five (5) strings are then connected to a single 84/112/140 MVA 34.5 - 230 kV (9% impedance) transformer (x2). The Large Generating Facility is located in Carbon County, Wyoming. Please see Exhibit 1 to Attachment A.

Control Area Requirements: Interconnection Customer shall interconnect and operate the Large Generating Facility in accordance with the Transmission Provider's Facility Interconnection Requirements for Transmission Systems, as may be revised from time to time, attached hereto as Exhibit 1 to Appendix C and by this reference incorporated herein.

Interconnection Details:
Metering. With reference to Article 7.1, Transmission Provider will own and maintain the bi-directional revenue Metering Equipment in Transmission Provider's Point of Interconnection substation at the Interconnection Customer's expense.

Under Frequency and Over Frequency Conditions. Consistent with LGIA Article 9.7.3, Transmission Provider shall design, procure, install and maintain frequency and voltage protection to trip feeder breakers in accordance with the settings shown in Exhibit 1 to Appendix C.

Reactive Power and Voltage Schedule. All interconnecting synchronous and non-synchronous generators are required to design their Generating Facilities with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices. For non-synchronous generators, the power factor requirement is to be measured at the high-side of the generator substation. The Generating Facility must provide dynamic reactive power to the system over the full range of real power output. If the Generating Facility is not capable of providing positive reactive support (i.e., supplying reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations, the facility will be required to add dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.

Generators shall be equipped with automatic voltage-control equipment and normally operated with the voltage regulation control mode enabled unless written authorization, or directive, from the Transmission Provider is given to operate in another control mode (e.g., constant power factor control). The control mode of generating units shall be accurately represented in operating studies. The generators shall be capable of operating continuously at their maximum power output at its rated field current within +/- 5% of its rated terminal voltage. Phasor Measurement Units will be required at any Generating Facilities with an individual or aggregate nameplate capacity of 75 MVA or greater.

As required by NERC standard VAR-001-1a, the Transmission Provider will provide a voltage schedule for the Point of Interconnection. In general, Generating Facilities should be operated so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Transmission Provider, in accordance with Transmission Provider Policy 139.

Generating Facilities capable of operating with a voltage droop are required to do so. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer's responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing. If the need for a master controller is identified, the cost and all related installation requirements will be the responsibility of the Interconnection Customer. Participation by the Generation Facility in subsequent interaction/coordination studies will be required pre- and post-commercial operation in order ensure system reliability.

All generators must meet the Federal Energy Regulatory Commission (FERC) and WECC low voltage ride-through requirements.

support (i.e., supplying reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations, the facility will be required to add dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.

Generators shall be equipped with automatic voltage-control equipment and normally operated with the voltage regulation control mode enabled unless written authorization, or directive, from the Transmission Provider is given to operate in another control mode (e.g., constant power factor control). The control mode of generating units shall be accurately represented in operating studies. The generators shall be capable of operating continuously at their maximum power output at its rated field current within +/- 5% of its rated terminal voltage. Phasor Measurement Units will be required at any Generating Facilities with an individual or aggregate nameplate capacity of 75 MVA or greater.

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Generating Facilities capable of operating with a voltage droop are required to do so. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer's responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing. If the need for a master controller is identified, the cost and all related installation requirements will be the responsibility of the Interconnection Customer. Participation by the Generation Facility in subsequent interaction/coordination studies will be required pre- and post-commercial operation in order ensure system reliability.

All generators must meet the Federal Energy Regulatory Commission (FERC) and WECC low voltage ride-through requirements.

As the Transmission Provider cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

Property Requirements. Subject to LGIA Articles 5.12 and 5.13, Interconnection Customer is required to obtain for the benefit of Transmission Provider at Interconnection Customer's sole cost and expense all real property rights, including but not limited to fee ownership, easements and/or rights of way, as applicable, for Transmission Provider owned facilities using forms acceptable to Transmission Provider. Transmission Provider shall not be obligated to accept any such real property right that does not, at Transmission Provider's sole discretion, confer sufficient rights to access, operate, construct, modify, maintain, place and remove Transmission Provider owned facilities or is otherwise conveyed using forms unacceptable to Transmission Provider. Further, all real property on which Transmission Provider's facilities are to be located must be environmentally, physically and operationally acceptable to the Transmission Provider in accordance with Good Utility Practice.

Subject to LGIA Article 5.14, Interconnection Customer is responsible for obtaining all permits required by all relevant jurisdictions for the project, including but not limited to, conditional use permits and construction permits; provided however, Transmission Provider shall obtain, at Interconnection Customer's cost and schedule risk, the permits necessary to construct Transmission Provider's facilities that are to be located on real property currently owned or held in fee or right by Transmission Provider.

Except as expressly waived in writing by an authorized officer of Transmission Provider, all of the foregoing permits and real property rights (conferring rights on real property that is environmentally, physically and operationally acceptable to Transmission Provider) shall be acquired as provided herein as a condition to Transmission Provider's contractual obligation to construct or take possession of facilities to be owned by the Transmission Provider under this Agreement. Transmission Provider shall have no liability for any project delays or cost overruns caused by delays in acquiring any of the foregoing permits and/or real property rights, whether such delay results from the failure to obtain such permits or rights or the failure of such permits or rights to meet the requirements set forth herein. Further, any completion dates, if any, set forth herein with regard to Transmission Provider's obligations shall be equitably extended based on the length and impact of any such delays.

With respect to the fiber optic cable on Interconnection Customer's tie line that will be owned by the Transmission Provider, the Interconnection Customer and the Transmission Provider agree that Transmission Provider's ownership and operation of fiber optic cable that is attached to poles or other structures that are owned or maintained by the Interconnection Customer is subject to LGIA Article 5.12, Good Utility Practice, and Transmission Provider's Interconnection Policy 139 (Exhibit 1 to Appendix C to LGIA).

Appendix D To LGIA

Security Arrangements Details

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

Automatic Data Transfer. Throughout the term of this Agreement, Interconnection Customer shall provide the data specified below by automatic data transfer to the Transmission Provider Control Center specified by Transmission Provider or to a Third-Party System Operator designated by Transmission Provider (or both):

From the Interconnection Customer's collector substation:

- Analogs:
  - Transformer # 1 real power
  - Transformer # 1 reactive power
  - Real power flow through 34.5 kV line feeder breaker T1-1
  - Reactive power flow through 34.5 kV line feeder breaker T1-1
  - Real power flow through 34.5 kV line feeder breaker T1-2
  - Reactive power flow through 34.5 kV line feeder breaker T1-2
  - Real power flow through 34.5 kV line feeder breaker T1-3
  - Reactive power flow through 34.5 kV line feeder breaker T1-3
  - Real power flow through 34.5 kV line feeder breaker T1-4
  - Reactive power flow through 34.5 kV line feeder breaker T1-4

  - Real power flow through 34.5 kV line feeder breaker T1-5
  - Reactive power flow through 34.5 kV line feeder breaker T1-5
  - Transformer # 2 real power
  - Transformer # 2 reactive power
  - Real power flow through 34.5 kV line feeder breaker T2-1
  - Reactive power flow through 34.5 kV line feeder breaker T2-1
  - Real power flow through 34.5 kV line feeder breaker T2-2
  - Reactive power flow through 34.5 kV line feeder breaker T2-2
  - Real power flow through 34.5 kV line feeder breaker T2-3
  - Reactive power flow through 34.5 kV line feeder breaker T2-3
  - Real power flow through 34.5 kV line feeder breaker T2-4
  - Reactive power flow through 34.5 kV line feeder breaker T2-4
  - Real power flow through 34.5 kV line feeder breaker T2-5
  - Reactive power flow through 34.5 kV line feeder breaker T2-5
  - A phase 230 kV transmission voltage
  - B phase 230 kV transmission voltage
  - C phase 230 kV transmission voltage
  - Average Wind speed
  - Average Plant Atmospheric Pressure (Bar)
  - Average Plant Temperature (Celsius)
- Status
  - 230 kV breaker T1
  - 34.5 kV collector circuit breaker T1-1
  - 34.5 kV collector circuit breaker T1-2
  - 34.5 kV collector circuit breaker T1-3
  - 34.5 kV collector circuit breaker T1-4
  - 34.5 kV collector circuit breaker T1-5
  - 230 kV breaker T2
  - 34.5 kV collector circuit breaker T2-1
  - 34.5 kV collector circuit breaker T2-2
  - 34.5 kV collector circuit breaker T2-3
  - 34.5 kV collector circuit breaker T2-4
  - 34.5 kV collector circuit breaker T2-5

Billing Meter Data. Bi-directional revenue meter at the Point of Interconnection will not be configured to allow direct dial-up access by Interconnection Customer. The Transmission Provider will provide alternatives, at the Interconnection Customer's expense, upon request.

Additional Data. Interconnection Customer shall, at its sole expense, provide any additional Generating Facility data reasonably required and necessary for the Transmission Provider to operate the Transmission System in accordance with Good Utility Practice and Exhibit 1 to Appendix C, Facility Interconnection Requirements for Transmission Systems.

Relay and Control Settings

Interconnection Customer must allow PacifiCorp to hold all Level 2 relay passwords for any control and/or protective device within its control at the Point of Interconnection and/or customer facility which directly impacts PacifiCorp's distribution and/or transmission systems. Level 2 passwords are those which allow actual modifications to control and/or relay settings. This will ensure PacifiCorp is aware of and approves any changes being made by the customer. Furthermore, this will ensure there are no negative impacts to PacifiCorp's distribution system, transmission system, or existing customers.

If Interconnection Customer requires modifications to the settings associated with control/protective devices connected to the distribution and/or transmission system, Interconnection Customer will contact PacifiCorp and provide in writing the justification for the proposed modifications. This will allow PacifiCorp to analyze the modifications and ensure there will be no negative impacts to connected systems and customers.

Any modifications of control and/or relay settings without review and acknowledgement of acceptance by PacifiCorp will be considered a breach of the Interconnection Agreement and grounds for permanent disconnection from the PacifiCorp system.

Appendix E To LGIA

Commercial Operation Date

This Appendix E is a part of the LGIA between Transmission Provider and Interconnection Customer.

[Date]

[Transmission Provider Address]

Re: _______________ Large Generating Facility

Dear _______________:

On **[Date]** **[Interconnection Customer]** has completed Trial Operation of Unit No. __. This letter confirms that [Interconnection Customer] commenced Commercial Operation of Unit No. ___ at the Large Generating Facility, effective as of **[Date plus one day]**.

Thank you.

[Signature]

[Interconnection Customer Representative]

Appendix F to LGIA

Addresses for Delivery of Notices and Billings

Notices, Billings and Payments:

Transmission Provider:

US Mail Deliveries:	PacifiCorp Transmission Services Attn: Central Cashiers Office PO Box 2757 Portland, OR 97208-2757
Other Deliveries:	Central Cashiers Office Attn: PacifiCorp Transmission Services 825 NE Multnomah Street, Suite 550 Portland OR 97232
Phone Number:	503-813-6774

Interconnection Customer:
Ekola Flats Wind Energy LLC
Attn: Jenny Liu
One South Wacker Dr, Suite 1800
Chicago, IL 60606

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

Director, Transmission Services	503-813-7237
Manager, Transmission Scheduling	503-813-5342
Manager, Interconnection Services	503-813-6496
Transmission Business Facsimile	503-813-6893

OASIS Address:
http://www.oasis.pacificorp.com/oasis/ppw/main.htmlx

Interconnection Customer:
Ekola Flats Wind Energy LLC
Attn: Jenny Liu
Telephone: 312-582-1821
Fax: 312-506-1456
Email: JLiu@invenergyllc.com

Appendix G to LGIA

INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating

plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or "GSU"), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 - 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the

fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. <u>Power Factor Design Criteria (Reactive Power)</u>

The following reactive power requirements apply only to a newly interconnecting wind generating plant that has executed a Facilities Study Agreement as of the effective

date of the Final Rule establishing the reactive power requirements for non-synchronous generators in section 9.6.1 of this LGIA (Order No. 827). A wind generating plant to which this provision applies shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

Exhibit 1 to Appendix A to LGIA

One-Line Diagram

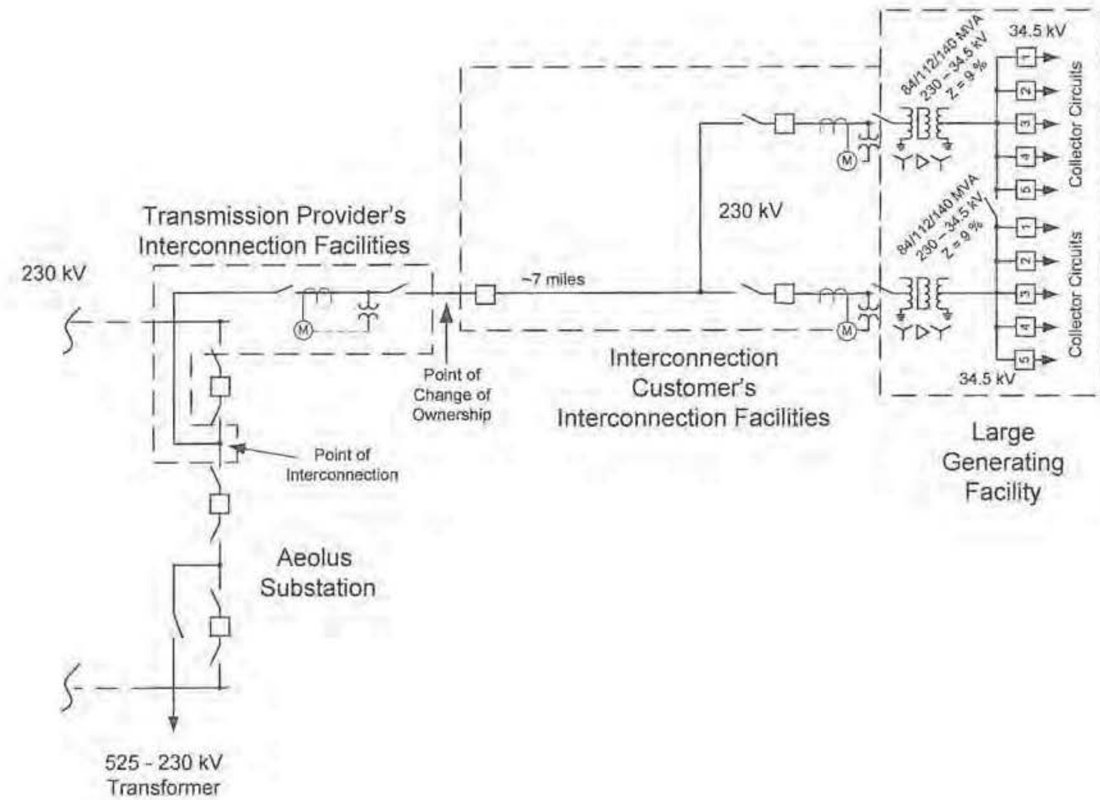


Exhibit 1 to Appendix B to LGIA

Scope of Work

Generating Facility Modifications

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer's Generation Facility.

Interconnection Customer to be Responsible For the following:

- Design, procure, install, and own all equipment required for the Large Generating Facility.
- Obtain all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the facilities required for the Q0706 Project. All easements and permits shall be recorded in the name of the Transmission Provider and shall be on forms acceptable to the Transmission Provider. All easements and rights of way will be obtained for durations acceptable to the Transmission Provider; this includes all permits/easements for ingress and egress prior to the start of construction.
  - Provide a separate fenced area along the perimeter of the Interconnection Customer's Generating Facility in which the Transmission Provider can install a control house for any protection and communication equipment. This area will share a fence and ground grid with the Generating Facility and have separate access. AC station service for the control house will be supplied by the Interconnection Customer.
- Provide a CDEGS grounding analysis.
- Design and install conduits, per Transmission Provider's standards, to the demarcation point.
- The collector substation batteries will be sized to carry the communication equipment with DC to DC converters.
- Demonstrate the reactive capability of the facility and the voltage control system prior to commercial operation. Conditions of operations include:
  - Operate in voltage control mode with the ability to deliver power output to the POI within the range of +/- 0.95 power factor. (Please see Standard Large Generator Interconnection Agreement, article 9.6.1 and 9.6.2 in OATT.) Any additional reactive

compensation must be designed such that the discrete switching of the reactive device, if required, does not cause step voltage changes greater than ± 3% at any load serving bus on the Transmission Provider's system.

- o As required by NERC standard VAR-001-1a, the Transmission Provider will provide a voltage schedule for the POI. Generating Facilities should be operated so as to maintain the voltage at the POI, or other designated point as deemed appropriate by Transmission Provider, between 1.00 per unit to 1.04 per unit. The Transmission Provider may also specify a voltage and/or reactive power bandwidth as needed to coordinate with upstream voltage control devices such as on-load tap changers. At the Transmission Provider's discretion, these values might be adjusted depending on operating conditions.
- o At low output levels, the Project needs to ensure that it maintains the power factor within ± 0.95 at the POI and minimize the reactive power flow towards the transmission system to prevent high voltages.
- o Generating Facilities capable of operating with a voltage droop are required to do so. Voltage droop control enables proportionate reactive power sharing among Generating Facilities. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer's responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing.
- o For areas with multiple Generating Facilities, additional studies may be required to determine whether or not critical interactions, including but not limited to control systems, exist. These studies, to be coordinated with Transmission Provider, will be the responsibility of the Interconnection Customer. If the need for a master controller is identified, the cost and all related installation requirements will be the responsibility of the Interconnection Customer.

- Design, procure, install, and own Phasor Measurement Units (PMUs).

- Provide a standard model from the WECC Approved Dynamic Model Library prior to interconnection, since the Transmission Provider cannot submit a user written model to WECC for inclusion in base cases. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.
- All generators must meet the Federal Energy Regulatory Commission (FERC) and WECC low voltage ride-through requirements as specified in the Interconnection Agreement.
- Prior to construction, arrange construction power with the Transmission Provider. The Project is within the Transmission Provider's service territory and both station service and temporary construction power metering shall conform to the Six State Electric Service Requirements manual.
- Prior to back feed, arrange distribution voltage retail meter service for electricity consumed by the Project and arrange back up station service for power that will be drawn from the transmission or distribution line when the Project is not generating. Interconnection Customer must call the PCCC Solution Center 1-800-640-2212 to arrange this service. Approval for back feed is contingent upon obtaining station service.
- Provide the following data points from the Q0706 collector substation:
  - Analogs:
    - Transformer # 1 real power
    - Transformer # 1 reactive power
    - Real power flow through 34.5 kV line feeder breaker T1-1
    - Reactive power flow through 34.5 kV line feeder breaker T1-1
    - Real power flow through 34.5 kV line feeder breaker T1-2
    - Reactive power flow through 34.5 kV line feeder breaker T1-2
    - Real power flow through 34.5 kV line feeder breaker T1-3
    - Reactive power flow through 34.5 kV line feeder breaker T1-3
    - Real power flow through 34.5 kV line feeder breaker T1-4
    - Reactive power flow through 34.5 kV line feeder breaker T1-4

- Real power flow through 34.5 kV line feeder breaker T1-5
- Reactive power flow through 34.5 kV line feeder breaker T1-5
- Transformer # 2 real power
- Transformer # 2 reactive power
- Real power flow through 34.5 kV line feeder breaker T2-1
- Reactive power flow through 34.5 kV line feeder breaker T2-1
- Real power flow through 34.5 kV line feeder breaker T2-2
- Reactive power flow through 34.5 kV line feeder breaker T2-2
- Real power flow through 34.5 kV line feeder breaker T2-3
- Reactive power flow through 34.5 kV line feeder breaker T2-3
- Real power flow through 34.5 kV line feeder breaker T2-4
- Reactive power flow through 34.5 kV line feeder breaker T2-4
- Real power flow through 34.5 kV line feeder breaker T2-5
- Reactive power flow through 34.5 kV line feeder breaker T2-5
- A phase 230 kV transmission voltage
- B phase 230 kV transmission voltage
- C phase 230 kV transmission voltage
- Average Wind speed
- Average Plant Atmospheric Pressure (Bar)
- Average Plant Temperature (Celsius)

- Status
  - 230 kV breaker T1
  - 34.5 kV collector circuit breaker T1-1
  - 34.5 kV collector circuit breaker T1-2
  - 34.5 kV collector circuit breaker T1-3
  - 34.5 kV collector circuit breaker T1-4
  - 34.5 kV collector circuit breaker T1-5
  - 230 kV breaker T2
  - 34.5 kV collector circuit breaker T2-1
  - 34.5 kV collector circuit breaker T2-2
  - 34.5 kV collector circuit breaker T2-3
  - 34.5 kV collector circuit breaker T2-4

- 34.5 kV collector circuit breaker T2-5

Transmission Provider to be Responsible For the following:

- Design, procure and install a small control building at a location provided and prepared by the Interconnection Customer inside the Generating Facility fence line.
- The list of major equipment identified for this portion of the Project is as follows:
  - (1) small control building AC and DC panels and temperature controlled
  - (1) 125VDC, 100Ah battery bank
  - (1) 130VDC, 12A battery charger
  - (1) GE D20 RTU
  - (1) 24" open frame rack (DNP 3.0 protocol with hard wired connections)
- Revenue metering is required for each of the two Interconnection Customer power transformers and will be located on the high side of each of the step-up transformers. The primary metering transformers shall be combination CT/VT extended range high accuracy metering with ratios to be determined during the design phase of the project.
- The Transmission Provider will design and procure the collector revenue metering panels. The panels shall be located inside the collector control house. The collector substation metering panel shall include two revenue quality meters, test switches, and all SCADA metering data terminated at a metering interposition block.
- An Ethernet or phone line is required for retail sales and generation accounting via the MV-90 translation system.

Tie Line Requirements and Point of Interconnection (Aeolus)

The following outlines the design, procurement, construction, installation, and ownership of equipment associated with the radial line connecting the Interconnection Customer's Generating Facility to the Transmission Provider's Point of Interconnection substation.

Interconnection Customer to be Responsible For the following:

- Obtain all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the facilities required for the Q0706 Project.

- Design and install approximately seven miles of 230kV transmission line between the Q0706 Generation Facility and the Aeolus substation. The Transmission Provider requires that the bus is built to the Transmission Provider's 230kV standard.
- Design and install ½" OPGW and attachment hardware per the Transmission Provider's standards with nodes and channel banks at both ends. The OPGW cable will be coiled on the above structure such that there is enough cable and conductor to reach the POI substation tower with normal sags. Also, provide all hardware for stringing of the last span of conductor and OPGW into the POI sub tower.
- This fiber is to be installed by the Interconnection Customer and upon acceptance will be owned and maintained by Transmission Provider. Channels will be crossed at Aeolus substation to the back bone communication system.
- Design and construct a single 230kV circuit breaker and associated equipment tie line substation adjacent to Aeolus substation with a common fence between the two facilities.
    - The ground mats between the Aeolus and the tie line substation will be tied together. Therefore, the Interconnection Customer must match the standards of the Aeolus substation.
- Conduit will be required to be installed between the Interconnection Customer's tie line substation and Aeolus substation. The Interconnection Customer will provide their conduit drawings and install the necessary conduit to demarcation point at the Point of Interconnection. The Transmission Provider will install the connecting conduit in the Aeolus substation.
- Design (per the Transmission Provider's standards) and install a dead-end structure with sufficient bus to allow for proper attachment to a 230kV disconnect switch inside the Transmission Provider's substation. The switch will be the Point of Change of Ownership.
- Provide the output from two sets of current transformers to be fed into the bus differential relays with a maximum current transformer ratio matching the maximum CT ratio of the breakers at Aeolus substation. The detection and clearing of faults on the tie line between the tie line and the collector substations will be the responsibility

of the Interconnection Customer. Facilities must be installed to detect and isolate the line if it is faulted in five cycles or less.

Transmission Provider to be Responsible For the following:

- Review the Interconnection Customer's design of the proposed new transmission line, OPGW and connection to the Aeolus substation structure for general conformance with Transmission Provider's construction standards.
- Provide a CDEGS grounding analysis of the Aeolus substation.
- Provide the Transmission Provider's construction standards and review the Interconnection Customer's design for the last bus support structure located outside the POI substation fence line to ensure compatibility with the termination switch.
- Connect the Interconnection Customer's last span of bus to the 230kV, disconnect switch at the change of ownership location including the OPGW cable. The Transmission Provider will maintain this last bus span at the Interconnection Customer's expense.
  - This short span of bus will be protected with a redundant bus differential relay systems. The bus differential relays will be located in Aeolus substation. The Interconnection Customer will need to provide the output from two sets of current transformers to be fed into the bus differential relays with a maximum current transformer ratio matching the maximum CT ratio of the breakers at Aeolus substation. If a fault is detected, both the 230 kV breakers in Aeolus substation and the 230 kV breaker in the Interconnection Customer's tie line substation will be tripped.
  - A relay at Aeolus substation will monitor the voltage magnitude and frequency. If the magnitude or frequency of the voltage is outside of normal range of operation a signal will be sent over the communication system to the collector substation. At the collector substation this signal is to trip open all of the 34.5 kV feeder breakers to disconnect the wind turbine generators. By tripping the 34.5 kV breakers instead of the 230 kV breakers the station service to the Generating Facility is maintained to facilitate the restoration of the generation. This relay will also have phase and ground directional overcurrent

elements set to operate for faults in the line between Shirley Basin substation and the Interconnection Customer's collector substation and serve as a back-up to the main protection installed by the Interconnection Customer.

Point of Interconnection (Aeolus substation)

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Point of Interconnection.

Interconnection Customer to be Responsible For the following:

- Obtain all necessary permits, rights of way and easements required for the construction at Aeolus substation.

Transmission Provider to be Responsible For the following:

- Complete design and construction of one transformer bay at Aeolus to terminate the tie line in. Three (3) feet of panel space will be required in the 230 kV control house. The following equipment will be installed:
  - (1) - 230 kV circuit breaker
  - (3) - 230 kV CCVT
  - (2) - 230 kV group operated breaker disconnect switch
  - (1) - 230 kV group operated line disconnect switch, with ground blade, with motor operator
  - (3) - 144 kV MCOV surge arrester
  - (1) - RTAC
- The interchange metering will be designed bidirectional and rated for the total net generation of the Project including metering the retail load (per tariff) delivered to the Interconnection Customer. The Transmission Provider will specify and order all interconnection revenue metering, including the instrument transformers, metering panels, junction box and secondary metering wire. The primary metering transformers shall be combination CT/VT extended range for high accuracy metering with ratios to be determined during the design phase of the Project.
- The metering design package will include two revenue quality meters, test switch, with DNP real time digital data terminated at a metering interposition block. One

meter will be designated a primary SCADA meter and a second meter will be used designated as backup with metering DNP data delivered to the alternate control center. The metering data will include bidirectional KWH KVARH, revenue quantities including instantaneous PF, MW, MVAR, MVA, including per phase voltage and amps data.

- An Ethernet connection is required for retail sales and generation accounting via the MV-90 translation system.
- Listed below is the data that will be supplied by the Aeolus substation.
  - Analogs:
    - Net Generation real power
    - Net Generator reactive power
    - Interchange energy register
- From Tie Substation Adjacent to Aeolus
  - Status:
    - 230 kV breaker
- Modify the Remedial Action Scheme for outages of the Aeolus-Anticline 500 kV transmission line to trip this project.
- Present the Aeolus-Anticline 500 kV RAS to the Western Electricity Coordinating Council ("WECC") Remedial Action Scheme Reliability Subcommittee ("RASRS") for approval.

Exhibit 1 to Appendix C to LGIA

Facility Connection Requirements for Transmission Systems

AGREEMENT TO AMEND STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

This **Agreement To Amend Standard Large Generator Interconnection Agreement** ("Agreement") is made and entered into this 1st day of November, 2018, by and between PacifiCorp, an Oregon corporation (the "Transmission Provider") and Ekola Flats Wind Energy LLC (Q706), a Delaware limited liability company (the "Interconnection Customer"). Transmission Provider and Interconnection Customer may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, Transmission Provider and Interconnection Customer have entered into a Standard Large Generator Interconnection Agreement, dated November 27, 2017, and designated as Original PacifiCorp Service Agreement No. 875 (the "Interconnection Agreement");

WHEREAS, the Interconnection Agreement conforms to PacifiCorp's *pro forma* Standard Large Generator Interconnection Agreement included in PacifiCorp's Open Access Transmission Tariff;

WHEREAS, Transmission Provider and Interconnection Customer have mutually agreed to amend one or more appendices and exhibits to the Interconnection Agreement; and

WHEREAS, Articles 30.9 and 30.10 of the Interconnection Agreement state that the Parties may by mutual agreement amend the Interconnection Agreement or its Appendices by a written instrument duly executed by the Parties, and such amendment shall become effective and a part of this Interconnection Agreement upon satisfaction of all Applicable Laws and Regulations;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

1.0 The Parties acknowledge and mutually agree that the following attached appendices and exhibits will be substituted in their entirety for the same appendices and exhibits in the Interconnection Agreement:

- Appendix A
- Appendix B
- Appendix C
- Appendix D
- Exhibit 1 to Appendix A
- Exhibit 1 to Appendix B

2.0 Service under the Interconnection Agreement with the amended appendices and exhibits will commence only upon execution by both Parties.

3.0 The Interconnection Agreement shall be designated by PacifiCorp as First Revised Service Agreement No. 875. PacifiCorp shall report the Interconnection Agreement, as amended, in the Electric Quarterly Report for the quarter in which service commences.

4.0 The Interconnection Agreement, with the attached substitute appendices and exhibits shall constitute the entire agreement between the Parties.

5.0 All other provisions of the Interconnection Agreement will continue to apply.

6.0 TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE, OR TO REQUEST THE CONSOLIDATION OF, ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

IN WITNESS WHEREOF, the Parties have executed this Agreement in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

PacifiCorp

By: Rick Vail

Title: VP, Transmission

Date: 11/1/18

Ekola Flats Wind Energy LLC (Q706)

By: James Williams

Title: Vice President

Date: October 31, 2018

Legal Reviewed

Appendix A to LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

1. **Interconnection Facilities:**

   (a) **Interconnection Customer's Interconnection Facilities:** Two (2) circuit breakers (one per step up transformer) connected to approximately one (1) mile of generator tie line for the Q706 collector substation to the Point of Interconnection (Aeolus substation). One circuit breaker will be located approximately adjacent to Aeolus substation. Please see Exhibit 1 to Attachment A.

   (b) **Transmission Provider's Interconnection Facilities:** Two (2) production meters located at the high side of the step up transformers at the Q706 collector substation, one (1) interchange meter at the Point of Change of Ownership, a 230 kV line position and bus expansion to terminate the Interconnection Customer's tie line, relay and grounding upgrades required for the new line position, and one new line position (dead end structure, disconnect switch, metering structure) located at the Point of Interconnection (Aeolus substation). Customer will also install fiber optic cable (to be owned by Transmission Provider) on generation tie line. Please see Exhibit 1 to Attachment A.

2. **Network Upgrades:**

   (a) **Stand Alone Network Upgrades:** None

   (b) **Other Network Upgrades:** None

3. **Distribution Upgrades:** None

4. **Point of Interconnection ("POI"):** The point at which Transmission Provider Interconnection Facilities connect to the substation bus at Aeolus substation (see Exhibit 1 to Appendix A).

5. **Point of Change of Ownership:** The point at which Interconnection Customer and Transmission Provider

Interconnection Facilities meet (see Exhibit 1 to Appendix A).

6. One-Line Diagram: is attached to this agreement as Exhibit 1 to Appendix A.

7. Contingent Facilities: The Point of Interconnection for this project is Aeolus 230 kV substation which is planned to be constructed as part of the Transmission Provider Gateway West D2 project. Aeolus substation, as well as the Gateway West Segment D2 500 kV transmission line (Aeolus-Anticline) are contingent for this project and must be in service prior to approval of generation activities for this project. If the schedule for completion of Aeolus substation or Gateway West Segment D2 are modified then the schedule for this project will need to be modified to align with the new completion date.

8. Estimated Project Cost: $2,862,000

Appendix B To LGIA

Milestones

Milestone/Date	Party
Execute Interconnection Agreement November 15, 2017	Interconnection Customer
Provision of Financial Security ($550,000) July 27, 2018	Interconnection Customer
Final Issue for Construction Design Package Provided August 31, 2018	Interconnection Customer
*Engineering & Procurement Commences November 6, 2018	Transmission Provider
**Energy Imbalance Market Modeling Data Submittal January 9, 2019	Interconnection Customer
Engineering Design Complete March 6, 2019	Transmission Provider
Property/Permits/ROW Procured April 10, 2019	Interconnection Customer
Construction Begins August 7, 2019	Transmission Provider
Facilities Receive Backfeed Power October 1, 2020	Interconnection Customer
***Initial Synchronization and Customer Generation Testing October 15, 2020	Interconnection
Commercial Operation November 1, 2020	Interconnection Customer

*As applicable and determined by the Transmission Provider, within 60 days of the Interconnection Customer's authorization for the Transmission Provider to begin engineering, the Interconnection Customer shall provide a detailed short circuit model of its generation system. This model must be constructed using the ASPEN OneLine short circuit simulation program and contain all individual electrical components of the Interconnection Customer's generation system.

**Any design modifications to the Interconnection Customer's Generating Facility after this date requiring updates to the Transmission Provider's network model will result in a minimum of 3 months added to all future milestones including Commercial Operation.

***The Transmission Provider's Gateway West Segment D2 500 kV transmission line (Aeolus-Anticline) must be in service prior to commencement of any generation activities.

Term of Agreement: In accordance with LGIA Article 2.2, the Parties agree that the term of the LGIA shall be ten (10) years from the Effective Date and shall be automatically renewed for each successive one-year period thereafter.

Construction Option: The Network Upgrades, Direct Assignment Facilities and Transmission Provider Interconnection Facilities will be designed, procured and constructed by the Transmission Provider in accordance with the Standard Option outlined in Article 5.1.1 of this Agreement. The Network Upgrades, Direct Assignment Facilities and Transmission Provider Interconnection Facilities shall be constructed in accordance with the Scope of Work attached to this LGIA as Exhibit 1 to Appendix B. The Network Upgrades, Direct Assignment Facilities and Transmission Provider's Interconnection Facilities shall be designed, procured and constructed in a timely manner to support the Milestone Dates stated above.

Appendix C To LGIA

Interconnection Details

Description of the Large Generating Facility: The Q0706 Large Generating Facility consists of ten (10) GE 2.3 MW 116/80 turbines connected to a single 34.5 kV string and fifty-four (54) Vestas V136/82 4.2 MW turbines connected to eleven (11) 34.5 kV strings for a total requested generation output of 250 MW. The strings are then connected to a two 90/120/150 MVA 34.5 - 230 kV (7.2% impedance) transformers. The Large Generating Facility is located in Carbon County, Wyoming. Please see Exhibit 1 to Attachment A.

Control Area Requirements: Interconnection Customer shall interconnect and operate the Large Generating Facility in accordance with the Transmission Provider's Facility Interconnection Requirements for Transmission Systems, as may be revised from time to time, attached hereto as Exhibit 1 to Appendix C and by this reference incorporated herein.

Interconnection Details:
Metering. With reference to Article 7.1, Transmission Provider will own and maintain the bi-directional revenue Metering Equipment in Transmission Provider's Point of Interconnection substation at the Interconnection Customer's expense.

Under Frequency and Over Frequency Conditions. Consistent with LGIA Article 9.7.3, Transmission Provider shall design, procure, install and maintain frequency and voltage protection to trip feeder breakers in accordance with the settings shown in Exhibit 1 to Appendix C.

Reactive Power and Voltage Schedule. All interconnecting synchronous and non-synchronous generators are required to design their Generating Facilities with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices. For non-synchronous generators, the power factor requirement is to be measured at the high-side of the generator substation. The Generating Facility must provide dynamic reactive power to the system over the full range of real power output. If the Generating

Facility is not capable of providing positive reactive support (i.e., supplying reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations, the facility will be required to add dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.

Generators shall be equipped with automatic voltage-control equipment and normally operated with the voltage regulation control mode enabled unless written authorization, or directive, from the Transmission Provider is given to operate in another control mode (e.g., constant power factor control). The control mode of generating units shall be accurately represented in operating studies. The generators shall be capable of operating continuously at their maximum power output at its rated field current within +/- 5% of its rated terminal voltage. Phasor Measurement Units will be required at any Generating Facilities with an individual or aggregate nameplate capacity of 75 MVA or greater.

As required by NERC standard VAR-001-4.2, the Transmission Provider will provide a voltage schedule for the Point of Interconnection. In general, Generating Facilities should be operated so as to maintain the voltage at the Point of Interconnection, typically between 1.00 per unit to 1.04 per unit, or other designated point as deemed appropriate by Transmission Provider. The Transmission Provider may also specify a voltage and/or reactive power bandwidth as needed to coordinate with upstream voltage control devices such as on-load tap changers. At the Transmission Provider's discretion, these values might be adjusted depending on operating conditions.

Generating Facilities capable of operating with a voltage droop are required to do so. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer's responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing. If the need for a master controller is identified, the cost and all related installation requirements will be the responsibility of the Interconnection Customer. Participation by the Generation Facility in subsequent interaction/coordination studies will be required pre- and post-commercial operation in order ensure system reliability.

All generators must meet the Federal Energy Regulatory Commission (FERC) and WECC low voltage ride-through requirements.

As the Transmission Provider cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

Property Requirements. Subject to LGIA Articles 5.12 and 5.13, Interconnection Customer is required to obtain for the benefit of Transmission Provider at Interconnection Customer's sole cost and expense all real property rights, including but not limited to fee ownership, easements and/or rights of way, as applicable, for Transmission Provider owned facilities using forms acceptable to Transmission Provider. Transmission Provider shall not be obligated to accept any such real property right that does not, at Transmission Provider's sole discretion, confer sufficient rights to access, operate, construct, modify, maintain, place and remove Transmission Provider owned facilities or is otherwise conveyed using forms unacceptable to Transmission Provider. Further, all real property on which Transmission Provider's facilities are to be located must be environmentally, physically and operationally acceptable to the Transmission Provider in accordance with Good Utility Practice.

Subject to LGIA Article 5.14, Interconnection Customer is responsible for obtaining all permits required by all relevant jurisdictions for the project, including but not limited to, conditional use permits and construction permits; provided however, Transmission Provider shall obtain, at Interconnection Customer's cost and schedule risk, the permits necessary to construct Transmission Provider's facilities that are to be located on real property currently owned or held in fee or right by Transmission Provider.

Except as expressly waived in writing by an authorized officer of Transmission Provider, all of the foregoing permits and real property rights (conferring rights on real property that is environmentally, physically and operationally acceptable to Transmission Provider) shall be acquired as provided herein as a condition to Transmission Provider's contractual obligation to construct or take possession of facilities to be owned by the Transmission Provider under this Agreement. Transmission Provider shall have no liability for any project delays or cost overruns caused by delays in acquiring any of the foregoing permits and/or real property rights, whether such delay results from the failure to obtain such permits or rights or the failure of such permits or rights to meet the requirements set forth herein. Further, any completion dates, if any, set forth herein with regard to Transmission Provider's obligations shall be equitably extended based on the length and impact of any such delays.

With respect to the fiber optic cable on Interconnection Customer's tie line that will be owned by the Transmission Provider, the Interconnection Customer and the Transmission Provider agree that Transmission Provider's ownership and operation of fiber optic cable that is attached to poles or other structures that are owned or maintained by the Interconnection Customer is subject to LGIA Article 5.12, Good Utility Practice, and Transmission Provider's Interconnection Policy 139 (Exhibit 1 to Appendix C to LGIA).

Appendix D To LGIA

Security Arrangements Details

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

Automatic Data Transfer. Throughout the term of this Agreement, Interconnection Customer shall provide the data specified below by automatic data transfer to the Transmission Provider Control Center specified by Transmission Provider or to a Third-Party System Operator designated by Transmission Provider (or both):

From the Interconnection Customer's collector substation:

- Analogs:
  - Transformer # 1 real power
  - Transformer # 1 reactive power
  - Real power flow through 34.5 kV line feeder breaker 1
  - Reactive power flow through 34.5 kV line feeder breaker 1
  - Real power flow through 34.5 kV line feeder breaker 2
  - Reactive power flow through 34.5 kV line feeder breaker 2
  - Real power flow through 34.5 kV line feeder breaker 3
  - Reactive power flow through 34.5 kV line feeder breaker 3
  - Real power flow through 34.5 kV line feeder breaker 4
  - Reactive power flow through 34.5 kV line feeder breaker 4
  - Real power flow through 34.5 kV line feeder

breaker 5
- Reactive power flow through 34.5 kV line feeder breaker 5
- Real power flow through 34.5 kV line feeder breaker 6
- Reactive power flow through 34.5 kV line feeder breaker 6
- Reactive power flow through 34.5 kV reactor breaker T1-R1
- Reactive power flow through 34.5 kV capacitor breaker T1-C1
- Transformer # 2 real power
- Transformer # 2 reactive power
- Real power flow through 34.5 kV line feeder breaker 7
- Reactive power flow through 34.5 kV line feeder breaker 7
- Real power flow through 34.5 kV line feeder breaker 8
- Reactive power flow through 34.5 kV line feeder breaker 8
- Real power flow through 34.5 kV line feeder breaker 9
- Reactive power flow through 34.5 kV line feeder breaker 9
- Real power flow through 34.5 kV line feeder breaker 10
- Reactive power flow through 34.5 kV line feeder breaker 10
- Real power flow through 34.5 kV line feeder breaker 11
- Reactive power flow through 34.5 kV line feeder breaker 11
- Real power flow through 34.5 kV line feeder breaker 12
- Reactive power flow through 34.5 kV line feeder breaker 12
- Reactive power flow through 34.5 kV reactor breaker T2-R1
- Reactive power flow through 34.5 kV capacitor breaker T2-C1
- A phase 230 kV transmission voltage
- B phase 230 kV transmission voltage
- C phase 230 kV transmission voltage
- Average Wind speed
- Average Plant Atmospheric Pressure (Bar)
- Average Plant Temperature (Celsius)

- Status
  - 230 kV breaker T1
  - 34.5 kV collector circuit breaker 1
  - 34.5 kV collector circuit breaker 2
  - 34.5 kV collector circuit breaker 3
  - 34.5 kV collector circuit breaker 4
  - 34.5 kV collector circuit breaker 5
  - 34.5 kV collector circuit breaker 6
  - 34.5 kV collector circuit breaker T1-R1
  - 34.5 kV collector circuit breaker T1-C1
  - 230 kV breaker T2
  - 34.5 kV collector circuit breaker 7
  - 34.5 kV collector circuit breaker 8
  - 34.5 kV collector circuit breaker 9
  - 34.5 kV collector circuit breaker 10
  - 34.5 kV collector circuit breaker 11
  - 34.5 kV collector circuit breaker 12
  - 34.5 kV collector circuit breaker T2-R1
  - 34.5 kV collector circuit breaker T2-C1

Billing Meter Data. Bi-directional revenue meter at the Point of Interconnection will not be configured to allow direct dial-up access by Interconnection Customer. The Transmission Provider will provide alternatives, at the Interconnection Customer's expense, upon request.

Additional Data. Interconnection Customer shall, at its sole expense, provide any additional Generating Facility data reasonably required and necessary for the Transmission Provider to operate the Transmission System in accordance with Good Utility Practice and Exhibit 1 to Appendix C, Facility Interconnection Requirements for Transmission Systems.

Relay and Control Settings

Interconnection Customer must allow Transmission Provider to hold all Level 2 relay passwords for any control and/or protective device within its control at the Point of Interconnection and/or customer facility which directly impacts Transmission Provider's distribution and/or transmission systems. Level 2 passwords are those which allow actual modifications to control and/or relay settings. This will ensure PacifiCorp is aware of and approves any changes being made by the customer. Furthermore, this will ensure there are no negative impacts to Transmission Provider's distribution system, transmission system, or existing customers.

If Interconnection Customer requires modifications to the settings associated with control/protective devices connected to the distribution and/or transmission system, Interconnection Customer will contact PacifiCorp and provide in writing the justification for the proposed modifications. This will allow PacifiCorp to analyze the modifications and ensure there will be no negative impacts to connected systems and customers.

Any modifications of control and/or relay settings without review and acknowledgement of acceptance by PacifiCorp will be considered a breach of the Interconnection Agreement and grounds for permanent disconnection from the Transmission Provider system.

Exhibit 1 to Appendix A to LGIA

One-Line Diagram

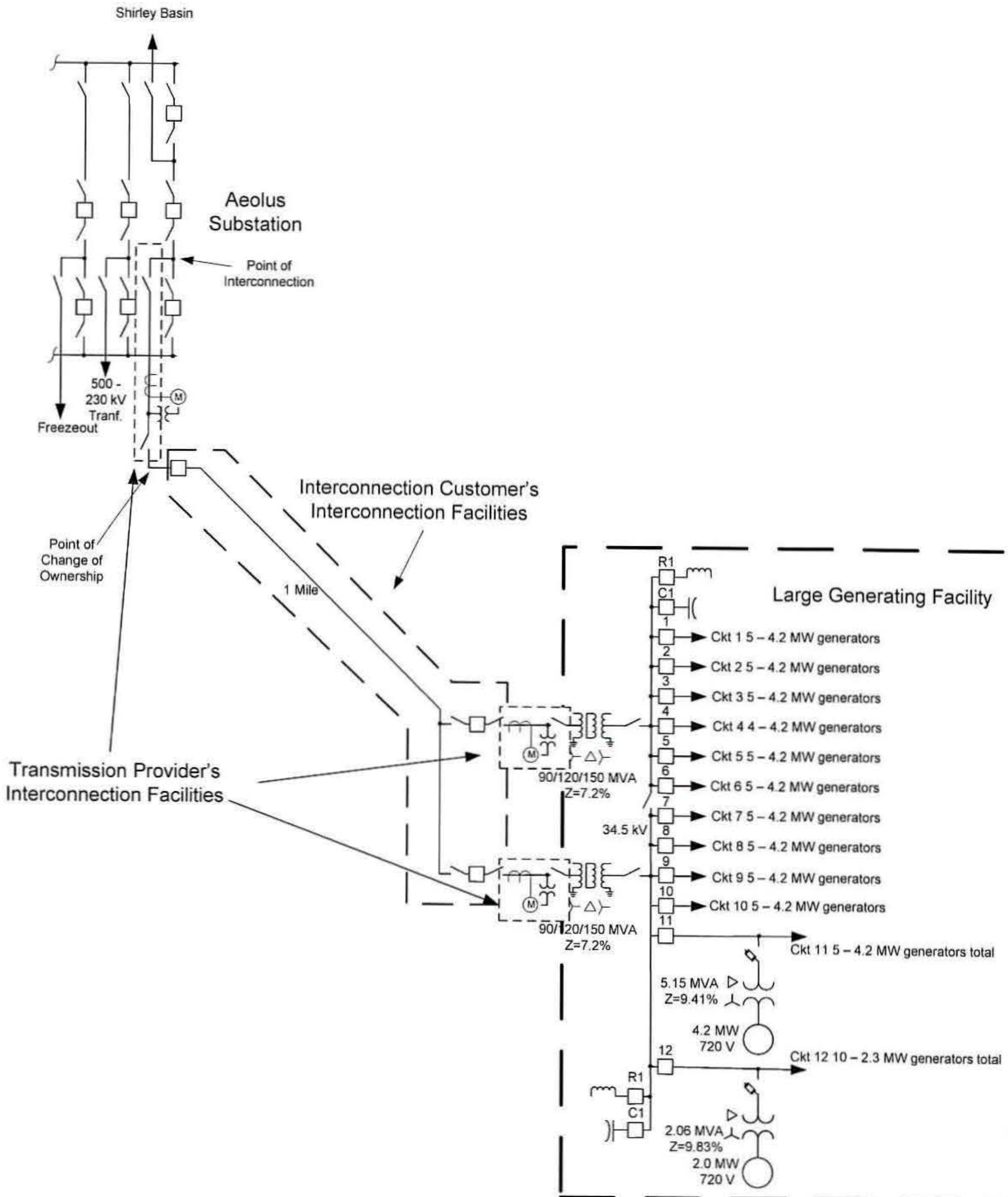


Exhibit 1 to Appendix B to LGIA

Scope of Work

Generating Facility Modifications

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer's Generation Facility.

Interconnection Customer to be Responsible For the following:

- Design, procure, install, and own all equipment required for the Large Generating Facility.
- Obtain all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the facilities required for the Q0706 Project. All necessary easements and permits procured by the Interconnection Customer for Transmission Provider Interconnection Facilities shall be recorded in the name of the Transmission Provider, shall be on forms acceptable to the Transmission Provider and obtained for durations acceptable to the Transmission Provider; this includes all permits/easements for ingress and egress prior to the start of construction.
- Provide a separate fenced area along the perimeter of the Interconnection Customer's Generating Facility in which the Transmission Provider can install a control building for metering and communication equipment. This area will share a fence and ground grid with the Generating Facility and have separate access. AC station service for the control building will be supplied by the Interconnection Customer.
- Provide a CDEGS grounding analysis of the control building site to the Transmission Provider.
- Demonstrate the reactive capability of the facility and the voltage control system prior to commercial operation. Conditions of operations include:
    - Operate in voltage control mode with the ability to deliver power output to the POI within the range of +/- 0.95 power factor. (Please see Standard Large Generator Interconnection Agreement, article 9.6.1 and 9.6.2 in OATT.) Any additional reactive compensation must be designed such that the discrete switching of the reactive device, if required, does not cause step voltage changes greater than ± 3% at

any load serving bus on the Transmission Provider's system.

- As required by NERC standard VAR-001-4.2, the Transmission Provider will provide a voltage schedule for the POI. Generating Facilities should be operated so as to maintain the voltage at the POI, or other designated point as deemed appropriate by Transmission Provider, typically between 1.00 per unit to 1.04 per unit. The Transmission Provider may also specify a voltage and/or reactive power bandwidth as needed to coordinate with upstream voltage control devices such as on-load tap changers. At the Transmission Provider's discretion, these values might be adjusted depending on operating conditions.
- At low output levels, the Project needs to ensure that it maintains the power factor within ± 0.95 at the POI and minimize the reactive power flow towards the transmission system to prevent high voltages.
- Generating Facilities capable of operating with a voltage droop are required to do so. Voltage droop control enables proportionate reactive power sharing among Generating Facilities. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer's responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing.
- For areas with multiple Generating Facilities, additional studies may be required to determine whether or not critical interactions, including but not limited to control systems, exist. These studies, to be coordinated with Transmission Provider, will be the responsibility of the Interconnection Customer. If the need for a master controller is identified, the cost and all related installation requirements will be the responsibility of the Interconnection Customer.

- Design, procure, install, and own Phasor Measurement Units (PMUs).
- Provide a standard model from the WECC Approved Dynamic Model Library prior to interconnection, since the Transmission Provider cannot submit a user written model

to WECC for inclusion in base cases. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

- All generators must meet the Federal Energy Regulatory Commission (FERC) and WECC low voltage ride-through requirements as specified in the Interconnection Agreement.
- Prior to construction, arrange construction power with the Transmission Provider. The Project is within the Transmission Provider's retail service territory and both station service and temporary construction power metering shall conform to the Six State Electric Service Requirements manual.
- Prior to back feed, arrange distribution voltage retail meter service for electricity consumed by the Project and arrange back up station service for power that will be drawn from the transmission or distribution line when the Project is not generating. Interconnection Customer must call the PCCC Solution Center 1-800-640-2212 to arrange this service. Approval for back feed is contingent upon obtaining station service.
- Procure, install, own and maintain a set of line relays that will detect and clear all faults on the tie line between the Interconnection Customer's collector and tie line substations in 5 cycles or less.
- Design, procure and install conduit and control cabling and hard wire the Interconnection Customer's source devices directly to the RTU located in the Transmission Provider's collector substation control building. Replicated values are not acceptable.
- Provide the following data points from the Q0706 collector substation:
  - Analogs:
    - Transformer # 1 real power
    - Transformer # 1 reactive power
    - Real power flow through 34.5 kV line feeder breaker 1
    - Reactive power flow through 34.5 kV line feeder breaker 1
    - Real power flow through 34.5 kV line feeder breaker 2
    - Reactive power flow through 34.5 kV line feeder breaker 2
    - Real power flow through 34.5 kV line feeder breaker 3

- Reactive power flow through 34.5 kV line feeder breaker 3
- Real power flow through 34.5 kV line feeder breaker 4
- Reactive power flow through 34.5 kV line feeder breaker 4
- Real power flow through 34.5 kV line feeder breaker 5
- Reactive power flow through 34.5 kV line feeder breaker 5
- Real power flow through 34.5 kV line feeder breaker 6
- Reactive power flow through 34.5 kV line feeder breaker 6
- Reactive power flow through 34.5 kV reactor breaker T1-R1
- Reactive power flow through 34.5 kV capacitor breaker T1-C1
- Transformer # 2 real power
- Transformer # 2 reactive power
- Real power flow through 34.5 kV line feeder breaker 7
- Reactive power flow through 34.5 kV line feeder breaker 7
- Real power flow through 34.5 kV line feeder breaker 8
- Reactive power flow through 34.5 kV line feeder breaker 8
- Real power flow through 34.5 kV line feeder breaker 9
- Reactive power flow through 34.5 kV line feeder breaker 9
- Real power flow through 34.5 kV line feeder breaker 10
- Reactive power flow through 34.5 kV line feeder breaker 10
- Real power flow through 34.5 kV line feeder breaker 11
- Reactive power flow through 34.5 kV line feeder breaker 11
- Real power flow through 34.5 kV line feeder breaker 12
- Reactive power flow through 34.5 kV line feeder breaker 12

        - Reactive power flow through 34.5 kV reactor breaker T2-R1
        - Reactive power flow through 34.5 kV capacitor breaker T2-C1
        - A phase 230 kV transmission voltage
        - B phase 230 kV transmission voltage
        - C phase 230 kV transmission voltage
        - Average Wind speed
        - Average Plant Atmospheric Pressure (Bar)
        - Average Plant Temperature (Celsius)
    - Status
        - 230 kV breaker T1
        - 34.5 kV collector circuit breaker 1
        - 34.5 kV collector circuit breaker 2
        - 34.5 kV collector circuit breaker 3
        - 34.5 kV collector circuit breaker 4
        - 34.5 kV collector circuit breaker 5
        - 34.5 kV collector circuit breaker 6
        - 34.5 kV collector circuit breaker T1-R1
        - 34.5 kV collector circuit breaker T1-C1
        - 230 kV breaker T2
        - 34.5 kV collector circuit breaker 7
        - 34.5 kV collector circuit breaker 8
        - 34.5 kV collector circuit breaker 9
        - 34.5 kV collector circuit breaker 10
        - 34.5 kV collector circuit breaker 11
        - 34.5 kV collector circuit breaker 12
        - 34.5 kV collector circuit breaker T2-R1
        - 34.5 kV collector circuit breaker T2-C1
- Provide and install fiber optic cable from the Transmission Provider's collector substation control building to the first structure on which the Interconnection Customer's transmission tie line fiber optic cable is installed.

Transmission Provider to be Responsible For the following:

- Design, procure and install a small control building at a location provided and prepared by the Interconnection Customer inside the Generating Facility fence line.
- The list of major equipment identified for this portion of the Project is as follows:
    - (1) small control building AC and DC panels and temperature controlled
    - (1) 125VDC, 100Ah battery bank

  - (1) 130VDC, 12A battery charger
  - (1) GE D20 RTU
  - (1) 24″ open frame rack (DNP 3.0 protocol with hard wired connections)
- Revenue metering is required for each of the two Interconnection Customer power transformers and will be located on the high side of each of the step-up transformers. The primary metering transformers shall be combination CT/VT extended range high accuracy metering with ratios to be determined during the design phase of the project.
- The Transmission Provider will design and procure the collector revenue metering panels. The panels shall be located inside the collector control house. The collector substation metering panel shall include two revenue quality meters, test switches, and all SCADA metering data terminated at a metering interposition block.
- An Ethernet or phone line is required for retail sales and generation accounting via the MV-90 translation system.
- Terminate the fiber provided by the Interconnection Customer in the control building.

Tie Line Requirements and Point of Interconnection (Aeolus)

The following outlines the design, procurement, construction, installation, and ownership of equipment associated with the radial line connecting the Interconnection Customer's Generating Facility and tie line substation.

Interconnection Customer to be Responsible For the following:

- Obtain all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the facilities required for the Interconnection Customer's 230 kV transmission line between the Interconnection Customer's collector and tie line substations. The Interconnection Customer will be responsible for all required regulatory or compliance reporting associated with its transmission tie line facilities.
- Design and install approximately one mile of 230kV transmission line between the Q0706 Generation Facility and tie line substation.

- Design, install, own and maintain OPGW and attachment hardware per the Transmission Provider's standards with nodes and channel banks at both ends. The OPGW cable will be coiled on the Interconnection Customer's transmission tie line such that there is enough cable and conductor to reach the POI substation tower with normal sags. Also, provide all hardware for stringing of the last span of conductor and OPGW into the POI sub tower.
- Provide the Transmission Provider one buffer tube, with at least 12 fibers, of the Interconnection Customer's OPGW fiber optic cable for the Transmission Provider's sole use.
- Splice the Transmission Provider's sole use buffer tube to the fiber running from the Transmission Provider's collector substation control building.
- Splice the Transmission Provider's sole use buffer tube to the fiber running from the Aeolus substation control building.

Transmission Provider to be Responsible For the following:

- Review the Interconnection Customer's design of the proposed new transmission line, OPGW and connection to the Aeolus substation structure for general conformance with Transmission Provider's construction standards.
- Provide the Transmission Provider's construction standards and review the Interconnection Customer's design for the last bus support structure located outside the POI substation fence line to ensure compatibility with the termination switch.

Interconnection Customer Tie Line Substation

The following outlines the design, procurement, construction, installation, and ownership of the Interconnection Customer's tie line substation.

Interconnection Customer to be Responsible For the following:

- Obtain all necessary permits, rights of way and easements required for the construction and continued maintenance of the Interconnection Customer's tie line substation.
- Design, procure, construct, own and maintain the Interconnection Customer's tie line substation (consisting of a sole 230 kV circuit breaker and

associated equipment) adjacent (less than 800') to the POI substation. This includes all radial transmission line relaying to the collector station, breaker failure protection and associated communications. The short line/bus segment between the tie line substation and the POI substation will be considered a bus section and will be protected with redundant bus differential relay systems.

- Provide and install two sets of current transformers to be fed into the bus differential relays with a maximum current transformer ratio matching the maximum CT ratio of the breakers at the POI substation. Provide and install conduit and cabling to the POI substation marshalling cabinet with these outputs.
- Construct the tie line substation such that the ground grid can be connected to the POI substation ground grid to support the installation of a Transmission Provider owned and maintained bus differential scheme. The Interconnect Customer is responsible to ensure the ground grid design supports safe step and touch potentials.
- The following data points are required from the Interconnection Customer's tie line substation:
  Status:
  - 230 kV breaker
- Provide and install conduits (number and size TBD) and control cabling between the Interconnection Customer tie line substation and marshalling cabinet just inside the fence of the POI substation to support copper circuits installed between the facilities. Hard wire all tie line substation status, control, and protection circuit interface to the POI substation to a Transmission Provider owned and maintained marshalling cabinet.
- If a transmission structure is required between the POI substation and the tie line substation, construct to Transmission Provider's current design and installation standards.
- Provide and install conductor, shield wire and line hardware in sufficient quantities to allow the Transmission Provider to terminate the tie line into POI substation dead-end structure strain insulators.

Transmission Provider to be Responsible For

- Provide the Interconnection Customer the necessary specifications to allow the ground grids of the Interconnection Customer's tie line substation and the POI substation to be tied together.
- Provide the Interconnection Customer the necessary specifications for the last bus/line segment of the Interconnection Customer's tie line substation and the POI substation to be connected.
- If a transmission structure is required between the POI substation and the tie line substation provide current standard design and installation standards to Interconnection Customer.

Point of Interconnection (Aeolus substation)

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Point of Interconnection.

Interconnection Customer to be Responsible For the following:

- Assist the Transmission Provider in the procurement of all necessary permits, rights of way and easements required for the construction at Aeolus substation.
- Test and commission of the communication path between the Interconnection Customer's collector substation and the POI substation in coordination with the Transmission Provider.

Transmission Provider to be Responsible For the following:

- Obtain all necessary permits, rights of way and easements required for the construction at Aeolus substation.
- Complete design and construction of one transformer bay at Aeolus to terminate the tie line in. Three (3) feet of panel space will be required in the 230 kV control house. The following equipment will be installed:
  - (1) - 230 kV circuit breaker
  - (3) - 230 kV CCVT
  - (2) - 230 kV group operated breaker disconnect switch
  - (1) - 230 kV group operated line disconnect switch, with ground blade, with motor operator
  - (3) - 144 kV MCOV surge arrester

  - (1) - RTAC
- Provide a CDEGS grounding analysis of the Aeolus substation.
- Connect the Interconnection Customer's last span of bus to the 230kV, disconnect switch at the change of ownership location. The Transmission Provider will maintain this last bus span at the Interconnection Customer's expense.
- This short span of bus between the POI substation and Interconnection Customer's tie line substation will be protected with a redundant bus differential relay system. If a fault is detected, both the 230 kV breakers in Aeolus substation and the 230 kV breaker in the Interconnection Customer's tie line substation will be tripped.
- A relay at Aeolus substation will monitor the voltage magnitude and frequency. If the magnitude or frequency of the voltage is outside of normal range of operation a signal will be sent over the communication system to the collector substation. At the collector substation this signal is to trip open all of the 34.5 kV feeder breakers to disconnect the wind turbine generators. By tripping the 34.5 kV breakers instead of the 230 kV breakers the station service to the Generating Facility is maintained to facilitate the restoration of the generation. This relay will also have phase and ground directional overcurrent elements set to operate for faults in the line between Shirley Basin substation and the Interconnection Customer's collector substation and serve as a back-up to the main protection installed by the Interconnection Customer.
- The interchange metering will be designed bidirectional and rated for the total net generation of the Project including metering the retail load (per tariff) delivered to the Interconnection Customer. The Transmission Provider will specify and order all interconnection revenue metering, including the instrument transformers, metering panels, junction box and secondary metering wire. The primary metering transformers shall be combination CT/VT extended range for high accuracy metering with ratios to be determined during the design phase of the Project.
- The metering design package will include two revenue quality meters, test switch, with DNP real time digital data terminated at a metering interposition block. One

meter will be designated a primary SCADA meter and a second meter will be used designated as backup with metering DNP data delivered to the alternate control center. The metering data will include bidirectional KWH KVARH, revenue quantities including instantaneous PF, MW, MVAR, MVA, including per phase voltage and amps data.

- An Ethernet connection is required for retail sales and generation accounting via the MV-90 translation system.
- Listed below is the data that will be supplied by the Aeolus substation.
    - Analogs:
        - Net Generation real power
        - Net Generator reactive power
        - Interchange energy register
- Review and confirm functionality of the Interconnection Customer's communications path between the collector substation and the POI substation.
- Modify the Remedial Action Scheme for various 500 kV outages to trip this project.
- Present the Aeolus-Anticline 500 kV RAS to the Western Electricity Coordinating Council ("WECC") Remedial Action Scheme Reliability Subcommittee ("RASRS") for approval.

INTERCONNECTION ASSIGNMENT AND ASSUMPTION AGREEMENT

THIS INTERCONNECTION ASSIGNMENT AND ASSUMPTION AGREEMENT (this "Assignment") is dated as of April 12, 2019, and is by and between **PACIFICORP**, an Oregon corporation, acting solely in its resource development capacity ("Assignee") **EKOLA FLATS WIND ENERGY LLC,** a Delaware limited liability company ("Assignor"). Capitalized terms used herein and not defined shall have the same meanings when used herein as in the Purchase Agreement (as hereinafter defined).

RECITALS

WHEREAS, Assignor and Assignee have entered into that certain Development Transfer Agreement, dated as of June 30, 2017 (the "Purchase Agreement"), pursuant to which, among other terms, Assignor has agreed to assign to Assignee all of its right, title and interest in and to the following items as of the date hereof (each of which shall have the meaning ascribed to it in the Purchase Agreement): (i) the Interconnection Agreement and (ii) the interconnection rights described on Exhibit A hereto (collectively, the "Interconnection Assets");

WHEREAS, pursuant to the Purchase Agreement, Assignee shall assume all of the Assumed Liabilities (as defined in the Purchase Agreement) relating to the Interconnection Assets; and

WHEREAS, Assignor and Assignee desire to enter into this Assignment to effect such assignment and assumption.

AGREEMENT

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Assignor and Assignee agree as follows effective as of the Closing:

1. Pursuant to and in accordance with the terms of the Purchase Agreement, Assignor hereby assigns, transfers, sells and conveys to Assignee all of Assignor's right, title and interest in and to the Interconnection Assets, free and clear of all Liens other than Permitted Liens.

2. Pursuant to and in accordance with the terms of the Purchase Agreement, Assignee hereby assumes, and agrees to pay and perform or discharge when due, the Assumed Liabilities relating to the Interconnection Assets.

3. None of the Excluded Assets and none of the Excluded Liabilities are assigned or transferred by Assignor to, or assumed by, Assignee.

4. Unless required by Applicable Law or otherwise agreed to by the Parties after the date hereof, Assignor and Assignee hereby agree that this Assignment and Assumption Agreement shall not be recorded in the public records of any Governmental Entity.

5. This Assignment is intended to evidence the consummation of the transactions contemplated by the Purchase Agreement. This Assignment is made without representation or

warranty except as expressly provided herein or as provided in and by the Purchase Agreement. This Assignment is in all respects subject to the provisions of the Purchase Agreement and is not intended in any way to supersede, limit, alter or qualify any obligation in or provision of the Purchase Agreement.

6. Assignor does hereby agree, from time to time as and when reasonably requested by Assignee, to execute and deliver (or cause to be executed and delivered) such documents or instruments and to take (or cause to be taken) such further or other actions, as may be reasonably necessary to carry out the purposes of this Assignment.

7. This Assignment shall be construed, interpreted and the rights of the parties hereto determined in accordance with the Laws of the State of New York without reference to its choice of law provisions.

8. This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and permitted assigns. This Assignment may be executed in counterparts, each of which will be deemed to be an original and all of which together constitute one and the same instrument.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF, Assignor and Assignee have caused this Interconnection Assignment and Assumption Agreement to be duly executed by their respective representatives thereunto duly authorized, all as of the day and year first above written.

ASSIGNOR

Ekola Flats Wind Energy LLC,
a Delaware limited liability company

By: ______________________
Name: James Williams
Title: Vice President

ASSIGNEE

PacifiCorp,
an Oregon corporation, solely in its resource development capacity

By:______________________ JP
Name: Chad A Teply
Title: Sr. VP, Bus. Policy & Dev.

CONSENT

Subject to and in accordance with Article 19 of the Interconnection Agreement, PacifiCorp, solely in its capacity as the "Transmission Provider" and "Transmission Owner" (as such terms are defined in the Interconnection Agreement), hereby consents to the assignment and assumption of the assigned Interconnection Assets as provided herein.

PacifiCorp,
an Oregon corporation

By:______________________________

Name: Rick Vail
Title: VP, Transmission
Date: 4/12/19

EXHIBIT A

TO INTERCONNECTION ASSIGNMENT AND ASSUMPTION AGREEMENT

Interconnection Agreement

The Large Generator Interconnection Agreement, dated as of November 27, 2017, by and between Ekola Flats Wind Energy LLC, a Delaware limited liability company ("Interconnection Customer"), and PacifiCorp, an Oregon corporation ("Transmission Provider" and "Transmission Owner"), as amended by that certain Agreement to Amend Large Generator Interconnection Agreement dated November 1, 2018.

Interconnection Rights

(a) Any and all of Interconnection Customer's rights, title and interest in the Interconnection Agreement, including (i) any and all amounts deposited with the Transmission Provider by Interconnection Customer and (ii) any and all refunds or credits due or owing from the Transmission Provider to Interconnection Customer, now or hereafter, and related to the Ekola Flats Project (it being acknowledged by the parties that the assignment of the rights set forth in this clause (a) shall not relieve Assignee of its obligations pursuant to Section 7.12 or 9.3(iii) of the Purchase Agreement);

(b) to the extent they have continued in effect after the execution and delivery of the Interconnection Agreement, any and all of the assignable rights and interests of Interconnection Customer in the Ekola Flats Project's transmission interconnection queue position;

(c) the application for interconnection of the Ekola Flats Project filed by Interconnection Customer with the Transmission Provider;

(d) any studies, reports or other documents regarding the Ekola Flats Project provided by the Transmission Provider or Transmission Owner;

(e) other rights with respect to the Interconnection Agreement that the Interconnection Customer may have with the Transmission Provider or Transmission Owner, and

(f) any and all other assignable rights relating to the interconnection of the Ekola Flats Project to the transmission grid.

REDACTED
Docket No. UE 374
Exhibit PAC/806
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

Ekola Flats Easements

February 2020

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

Docket No. UE 374
Exhibit PAC/807
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

Permit Status Record Ekola Flats

February 2020

CPCN/Project Name: **Ekola Flats Project**
(250 MW wind facility and associated infrastructure)

	Agency	Required Permit	Date Obtained
1	Federal Aviation Administration	Notice of Proposed Construction or Alteration	November 27, 2018
2	Department of Commerce National Telecommunication Information Agency	Impacts to Telecommunication Systems and Radar	September 13, 2018
3	U.S. Environmental Protection Agency (EPA)	Spill Prevention Controls and Countermeasure Plan (SPCC)	Contractor will acquire permit prior to construction mobilization
4	U.S. Army Corps of Engineers	Clean Water Act Section 404 / Individual or Nationwide 12 Permit	If needed, Contractor will acquire permit prior to construction mobilization
5	U.S. Fish and Wildlife Service	Section 7 Consultation / Biological Opinion	Contractor will acquire permit prior to construction mobilization
6	WY Department of Environmental Quality	Wyoming Industrial Development Information and Siting Act /Industrial Siting Council Order	October 15, 2018
7	WY Department of Environmental Quality	Wyoming Pollutant Discharge Elimination System (WYPDES) - Large Construction General Permit (WYR10-000) - Notice of Intent (NOI) and Storm Water Pollution and Prevention Plan (SWPPP)	Contractor will acquire permit prior to construction mobilization
8	WY Department of Environmental Quality	Temporary/Portable Source Air Permit	Contractor will acquire permit prior to construction mobilization
9	WY Department of Environmental Quality	Permit to Construct Small Wastewater Facilities (Septic Tanks and Leach fields)	Contractor will acquire permit prior to construction mobilization
10	WY Department of Environmental Quality	Section 401 Water Quality Certification	Contractor will acquire permit prior to construction mobilization
11	WY Department of Environmental Quality	Temporary Increase in Turbidity	Contractor will acquire permit prior to construction mobilization
12	WY Department of Environmental Quality	General Permit for Wetland Mitigation	Contractor will acquire permit prior to construction mobilization
13	WY State Engineers Office	Permit to appropriate groundwater (use, storage, wells, dewatering) or water stored in impoundments or reservoirs W.S. 41 3-901 through 41-3-938, as amended (Form U.W. 5)	Contractor will acquire permit prior to construction mobilization
14	WY Public Service Commission	Certificate of Public Convenience and Necessity	Conditional Permit Granted October 8, 2018
15	WY Department of Transportation	Port of Entry	Contractor will acquire permit prior to wind turbine generator supplier delivery
16	WY Department of Transportation	Rights of way encroachment	Contractor will acquire permit prior to wind turbine generator supplier delivery
17	WY Department of Transportation	Permit for Oversized / Overweight Loads	Wind turbine generator supplier will acquire prior to wind turbine generator delivery
18	WY Office of State Lands and Investments	Special Use Lease	June 22, 2018 (See Attachment 1 for agreement)
19	Albany County	Conditional Use Permit (CUP) - Wind Project	Not Required, project area no longer in Albany County
20	Albany County	Building Permit	Not Required, project area no longer in Albany County
21	Carbon County	Conditional Use Permit (CUP) - Wind Project	July 3, 2018
22	Carbon County	Building Permit	Contractor will acquire permit prior to construction mobilization

Docket No. UE 374
Exhibit PAC/808
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

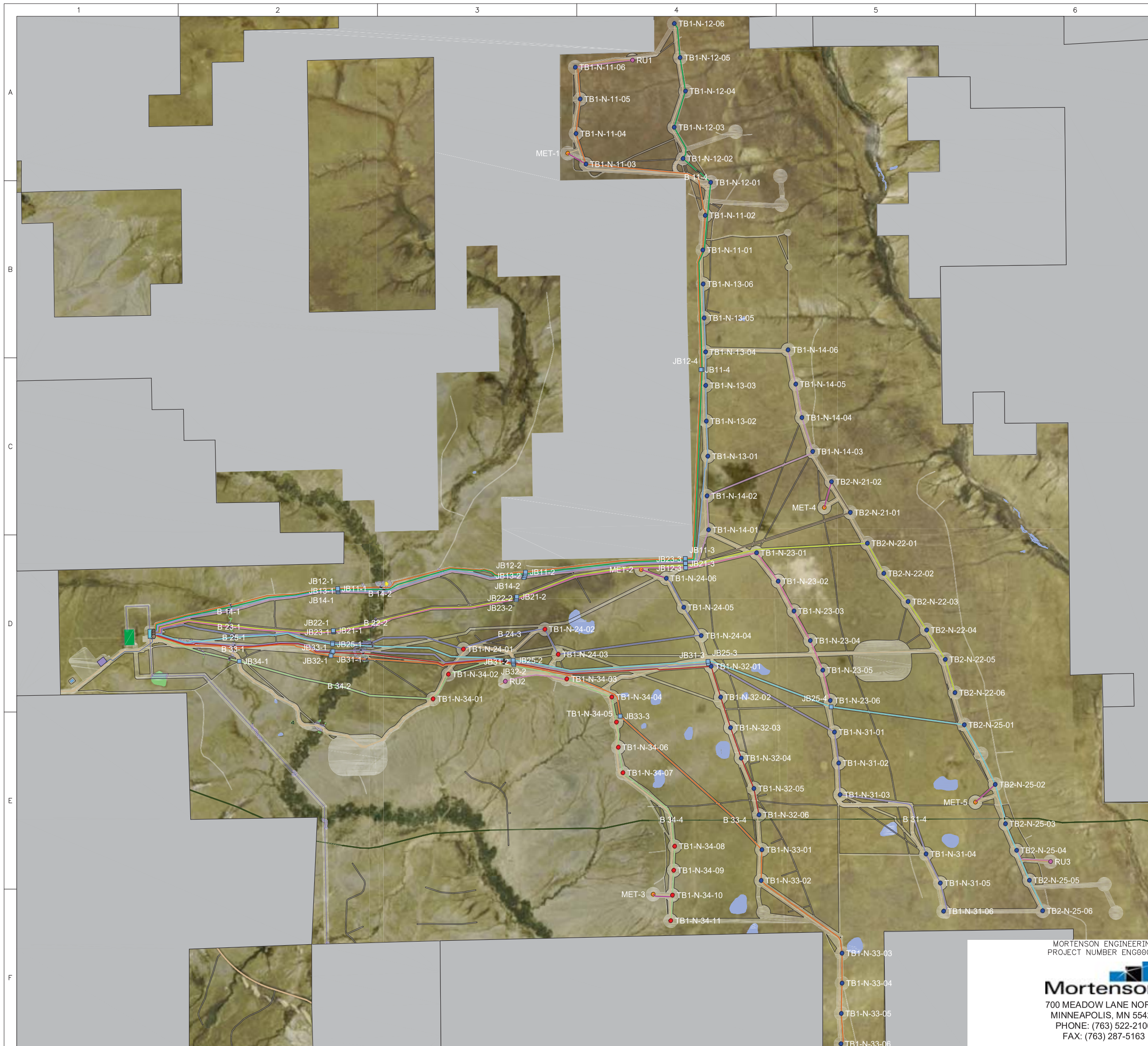
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

Site Plan TB Flats

February 2020



LEGEND

TURBINES	TBFlats_WW_IFC_RoadCL_TwoTrack_20190510
VESTAS 4.3 MW	Wetlands_Major_20170802
VESTAS 2.0 MW	Wetlands_Minor_20170802
SUBSTATION BREAKERS	TBFlats_WW_IFC_WaterPonds_20190510
JUNCTION BOXES	TB_Flats_Del_Wetland_Waterco 50Ft_Cult_Buffer
FEEDER 11	TBFlats_Pipeline_TopoMap
FEEDER 12	TBFlats_BuriedPipeline_SiteVisit
FEEDER 13	TBFlats_WW_IFC_TransmissionLine_20190510
FEEDER 14	TBFlats_WW_CulturalSites_AVOID_20190507
FEEDER 21	TBFlats_WW_DelineatedWetlands_FINAL_20190507
FEEDER 22	TBFlats_WW_SurveyedCorridorFinal_20190517
FEEDER 23	TB FLATS LEASE EXCEPTIONS
FEEDER 24	TB FLATS LEASE BOUNDARY
FEEDER 25	Easement_Only_Land_20180522
FEEDER 31	TBFlats_WW_IFC_SubstationTB1_20190510
FEEDER 32	ShirleyBasinSubstation
FEEDER 33	TBFlats_WW_IFC_OM_20190510
FEEDER 34	BLM_Carbon
BORE	BLM_Albany
TBFlats_WW_IFC_Fiber_20190510	TBFlats_WW_IFC_ADLS_20190510
MET TOWER CABLE	ADLS Tower Cable
TBFlats_WW_IFC_MetTowers_20190510	
TBFlats_WW_IFC_ExistingRoadCL_20190510	
TBFlats_WW_IFC_RoadCL_20190612	

NOTES:
1. THIS DRAWING'S SCOPE IS DEFINING THE COLLECTION CABLE ROUTING REQUIREMENTS. ADDITIONAL SCOPES SHOWN FOR COORDINATION ONLY AND SHALL NOT BE USED TO CONSTRUCT FROM. REFERENCE APPROPRIATE SCOPE CONSTRUCTION DOCUMENTS FOR REQUIREMENTS. FOR EXAMPLE, REFERENCE CIVIL CONSTRUCTION PLANS FOR PROJECT CIVIL REQUIREMENTS, AND REFERENCE T-LINE CONSTRUCTION PLANS FOR PROJECT T-LINE REQUIREMENTS.
2. PRIOR TO CONSTRUCTION VERIFY ALL EXISTING INFRASTRUCTURE LOCATIONS WITH ONE-CALL AND GPS LOCATES.
3. THE TBFlats_Pipeline_TopoMap FILE REFERS TO AN UNDERGROUND TELEPHONE LINE.
4. REFERENCE 116194-CL-310.01 SERIES FOR FEEDER ROUTING DIAGRAMS.

MORTENSON ENGINEERING
PROJECT NUMBER ENG00024
Mortenson
700 MEADOW LANE NORTH
MINNEAPOLIS, MN 55422
PHONE: (763) 522-2100
FAX: (763) 287-5163

SAP#			
PL#	512101		
DATE	06/12/2019		
ENG	SL	DES	CL
DR	MH	CH	MF
APPROVAL			

TB FLATS 1

COLLECTION SYSTEM OVERALL PLAN

PACIFICORP
WIND

SCALE: NONE | SHEET | 116194-CL-300.01 | REV. 0

No.	DATE	REVISION	BY	CHK	APP
0	06/12/19	ISSUED FOR CONSTRUCTION	MH	MF	SL

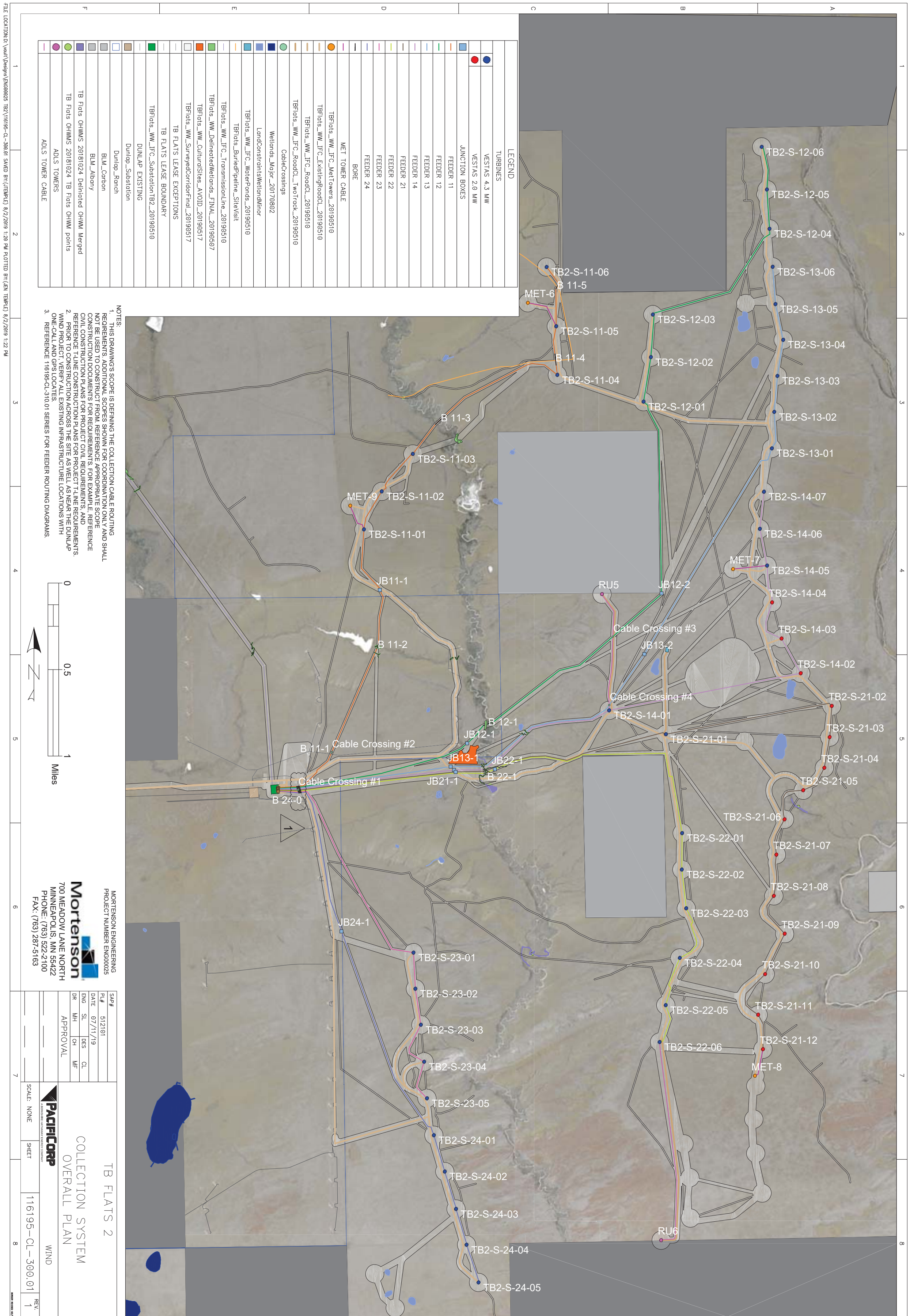
No.	DATE	REVISION	BY	CHK	APP

DRAWING No.	REFERENCE DRAWINGS

DRAWING No.	REFERENCE DRAWINGS

FILE LOCATION:D:\Vault\Designs\ENG00024 TB1\116194-CL-300.01 SAVED BY:(JTEMPLE) 6/12/2019 11:29 AM PLOTTED BY:(JEN TEMPLE) 6/12/2019 11:31 AM

Exhibit PAC/808
Teply/2



No.	DATE	REVISION	BY	CHK	APP	No.	DATE	REVISION	BY	CHK	APP	DRAWING No.	REFERENCE DRAWINGS	DRAWING No.	REFERENCE DRAWINGS
0	07/11/19	ISSUED FOR CONSTRUCTION	JT	MF	SL										
1	08/06/19	ADDED BORES UNDER DUNLAP CABLE NEAR SUBSTATION	JT	MF	SL										

REDACTED
Docket No. UE 374
Exhibit PAC/809
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

TB Flats Assessment, Wind Resource and Energy Production Estimate, and Wind Resource Assessment Review

February 2020

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

REDACTED
Docket No. UE 374
Exhibit PAC/810
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

TB Flats Project Schedule

February 2020

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

Docket No. UE 374
Exhibit PAC/811
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

Large Generator Interconnection Agreement TB Flats

February 2020

RECEIVED
FEB 18 2019
Transmission Services

STANDARD LARGE GENERATOR

INTERCONNECTION AGREEMENT (LGIA)
between
PACIFICORP, on behalf of its Transmission function
and
PacifiCorp, on behalf of its Marketing function
TB Flats I – Q707

TABLE OF CONTENTS

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this 19th day of February, 20 19 by and between PacifiCorp, on behalf of its Marketing function, a Corporation organized and existing under the laws of the State of Oregon ("Interconnection Customer") with a Large Generating Facility), and PacifiCorp, on behalf of its Transmission function, a corporation organized and existing under the laws of the State of Oregon ("Transmission Provider and/or Transmission Owner"). Interconnection Customer and Transmission Provider each may be referred to as a "Party" or collectively as the "Parties."

Recitals

WHEREAS, Transmission Provider operates the Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and,

WHEREAS, Interconnection Customer and Transmission Provider have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility with the Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (Tariff).

Article 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection System Impact Study.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or

Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not

include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission

Provider's Transmission System. The scope of the study is defined in Section 43 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System, the scope of which is described in Section 41 of the Standard Large Generator Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility

pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

NERC shall mean the North American Electric Reliability Council or its successor organization.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of

constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose.

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in the Transmission Provider's Tariff.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission Provider's Transmission System or on other delivery systems or other generating systems to which the Transmission Provider's Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC,

and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Large Generator Interconnection Agreement to the extent necessary.

Transmission Provider shall mean the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Variable Energy Resource shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Article 2. Effective Date, Term, and Termination

2.1 Effective Date. This LGIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this LGIA with FERC upon execution in accordance with Article 3.1, if required.

2.2 Term of Agreement. Subject to the provisions of Article 2.3, this LGIA shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as Interconnection Customer may request (Term to be specified in individual agreements) and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures.

2.3.1 Written Notice. This LGIA may be terminated by Interconnection Customer after giving Transmission Provider ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

2.3.2 Default. Either Party may terminate this LGIA in accordance with Article 17.

2.3.3 Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this LGIA, which notice has been accepted for filing by FERC.

2.4 Termination Costs. If a Party elects to terminate this Agreement pursuant to Article 2.3 above, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party, as of the date of the other Party's receipt of such notice of

termination, that are the responsibility of the Terminating Party under this LGIA. In the event of termination by a Party, the Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this LGIA, unless otherwise ordered or approved by FERC:

2.4.1 With respect to any portion of Transmission Provider's Interconnection Facilities that have not yet been constructed or installed, Transmission Provider shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Provider shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Provider for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Provider shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Provider to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this LGIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities

and equipment, and other expenses including any Network Upgrades for which Transmission Provider has incurred expenses and has not been reimbursed by Interconnection Customer.

2.4.2 Transmission Provider may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Provider shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this LGIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 **Disconnection.** Upon termination of this LGIA, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 **Survival.** This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this LGIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

Article 3. Regulatory Filings

3.1 Filing. Transmission Provider shall file this LGIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this LGIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

Article 4. Scope of Service

4.1 Interconnection Product Options. Interconnection Customer has selected the following (checked) type of Interconnection Service:

X **4.1.1 Energy Resource Interconnection Service.**

4.1.1.1 The Product. Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interconnection Service, Transmission Provider shall construct facilities identified in Attachment A.

4.1.1.2 Transmission Delivery Service Implications. Under Energy

Resource Interconnection Service, Interconnection Customer will be eligible to inject power from the Large Generating Facility into and deliver power across the interconnecting Transmission Provider's Transmission System on an "as available" basis up to the amount of MWs identified in the applicable stability and steady state studies to the extent the upgrades initially required to qualify for Energy Resource Interconnection Service have been constructed. Where eligible to do so (e.g., PJM, ISO-NE, NYISO), Interconnection Customer may place a bid to sell into the market up to the maximum identified Large Generating Facility output, subject to any conditions specified in the interconnection service approval, and the Large Generating Facility will be dispatched to the extent Interconnection Customer's bid clears. In all other instances, no transmission delivery service from the Large Generating Facility is assured, but Interconnection Customer may obtain Point-to-Point Transmission Service, Network Integration Transmission Service, or be used for secondary network transmission service, pursuant to Transmission Provider's Tariff, up to the maximum output identified in the stability and steady state studies. In those instances, in order for Interconnection Customer to obtain the right to deliver or inject energy beyond the Large Generating Facility Point of Interconnection or to improve its ability to do so, transmission

delivery service must be obtained pursuant to the provisions of Transmission Provider's Tariff. The Interconnection Customer's ability to inject its Large Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of Transmission Provider's Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of firm Point-to-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

☐ **4.1.2 Network Resource Interconnection Service.**

4.1.2.1 The Product. Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as all Network Resources. To the extent Interconnection Customer wants to receive Network Resource Interconnection Service, Transmission Provider shall construct the facilities identified in Attachment A to this LGIA.

4.1.2.2 Transmission Delivery Service Implications. Network Resource

Interconnection Service allows Interconnection Customer's Large Generating Facility to be designated by any Network Customer under the Tariff on Transmission Provider's Transmission System as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Large Generating Facility in the same manner as it accesses Network Resources. A Large Generating Facility receiving Network Resource Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Large Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Large Generating Facility has not been designated as a Network Resource by any load, it cannot be

required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or firm Point-to-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Large Generating Facility to any particular load on Transmission Provider's Transmission System without incurring congestion costs. In the event of transmission constraints on Transmission Provider's Transmission System, Interconnection Customer's Large Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that Interconnection Customer's Large Generating Facility be designated

as a Network Resource by a Network Service Customer under the Tariff or that Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does designate the Large Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interconnection Service, any future transmission service request for delivery from the Large Generating Facility within Transmission Provider's Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Large Generating Facility be undertaken, regardless of whether or not such Large Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Large Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Large Generating Facility outside

Transmission Provider's Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

4.2 **Provision of Service.** Transmission Provider shall provide Interconnection Service for the Large Generating Facility at the Point of Interconnection.

4.3 **Performance Standards.** Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is a Transmission Provider or Transmission Owner, then that Party shall amend the LGIA and submit the amendment to FERC for approval.

4.4 **No Transmission Delivery Service.** The execution of this LGIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

4.5 **Interconnection Customer Provided Services.** The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.5.1.

Interconnection Customer shall be paid for such services in accordance with Article 11.6.

Article 5. Interconnection Facilities Engineering, Procurement, and Construction

5.1 **Options.** Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either Standard Option or Alternate Option set forth below for

completion of Transmission Provider's Interconnection Facilities and Network Upgrades as set forth in Appendix A, Interconnection Facilities and Network Upgrades, and such dates and selected option shall be set forth in Appendix B, Milestones.

5.1.1 **Standard Option.** Transmission Provider shall design, procure, and construct Transmission Provider's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Provider shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Provider reasonably expects that it will not be able to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the specified dates, Transmission Provider shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 **Alternate Option.** If the dates designated by Interconnection Customer are acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities by the designated dates.

If Transmission Provider subsequently fails to complete Transmission Provider's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to

complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B, Milestones; Transmission Provider shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable RTO or ISO refuses to grant clearances to install equipment.

5.1.3 **Option to Build.** If the dates designated by Interconnection Customer are not acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. Transmission Provider and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 **Negotiated Option.** If Interconnection Customer elects not to exercise its option under Article 5.1.3, Option to Build, Interconnection Customer shall so notify Transmission Provider within thirty (30) Calendar Days, and the Parties shall in

good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades by Interconnection Customer) pursuant to which Transmission Provider is responsible for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, Transmission Provider shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Network Upgrades pursuant to 5.1.1, Standard Option.

5.2 General Conditions Applicable to Option to Build. If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Provider;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Provider shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider;

(5) at any time during construction, Transmission Provider shall have the right to gain unrestricted access to Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Provider, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider for claims arising from Interconnection Customer's construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) Interconnection Customer shall transfer control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Provider's Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Provider;

(10) Transmission Provider shall approve and accept for operation and maintenance Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information, and any other documents that are reasonably required by Transmission Provider to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

5.3 Liquidated Damages. The actual damages to Interconnection Customer, in the event Transmission Provider's Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Provider pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Provider to Interconnection Customer in the event that Transmission Provider does not complete any portion of Transmission Provider's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of Transmission Provider's Interconnection Facilities and Network

Upgrades, in the aggregate, for which Transmission Provider has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades for which Transmission Provider has assumed responsibility to design, procure, and construct. The foregoing payments will be made by Transmission Provider to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Transmission Provider's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for the Large Generating Facility's Trial Operation or to export power from the Large Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for Large Generating Facility's Trial Operation or to export power from the Large Generating Facility, but for Transmission Provider's delay; (2) Transmission Provider's failure to meet the specified dates is the result of the action or inaction of Interconnection Customer or any other Interconnection Customer who has entered into an LGIA with Transmission Provider or any cause beyond Transmission Provider's reasonable control or reasonable ability to cure; (3) the interconnection Customer has assumed responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 Power System Stabilizers. The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative. The requirements of this paragraph shall not apply to wind generators.

5.5 Equipment Procurement. If responsibility for construction of Transmission Provider's Interconnection Facilities or Network Upgrades is to be borne by Transmission Provider, then Transmission Provider shall commence design of Transmission Provider's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 Transmission Provider has completed the Facilities Study pursuant to the Facilities Study Agreement;

5.5.2 Transmission Provider has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.5.3 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.6 Construction Commencement. Transmission Provider shall commence construction of Transmission Provider's Interconnection Facilities and Network Upgrades for which it is responsible as soon as

practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Provider's Interconnection Facilities and Network Upgrades;

5.6.3 Transmission Provider has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.6.4 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.7 **Work Progress.** The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Either Party may, at any time, request a progress report from the other Party. If, at any time, Interconnection Customer determines that the completion of Transmission Provider's Interconnection Facilities will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider of such later date upon which the completion of Transmission Provider's Interconnection Facilities will be required.

5.8 **Information Exchange.** As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with Transmission Provider's Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 Limited Operation. If any of Transmission Provider's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Large Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Large Generating Facility and Interconnection Customer's Interconnection Facilities may operate prior to the completion of Transmission Provider's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. Transmission Provider shall permit Interconnection Customer to operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.10 Interconnection Customer's Interconnection Facilities ('ICIF'). Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.10.1 Interconnection Customer's Interconnection Facility Specifications. Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Provider at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Provider shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's

submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 **Transmission Provider's Review**. Transmission Provider's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Provider, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider.

5.10.3 **ICIF Construction.** The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Large Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Large Generating Facility. The Interconnection Customer shall provide Transmission Provider specifications for the excitation system, automatic voltage regulator, Large

Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.11 Transmission Provider's Interconnection Facilities Construction. Transmission Provider's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Provider shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Provider's Interconnection Facilities [include appropriate drawings and relay diagrams].

Transmission Provider will obtain control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

5.12 Access Rights. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to the other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the Transmission System; (ii) operate and maintain the Large Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed

from time to time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners. If any part of Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Provider or Transmission Owner, Transmission Provider or Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

5.14 Permits. Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities. Interconnection Customer may request Transmission Provider to construct, and Transmission Provider shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not

scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 Suspension. Interconnection Customer reserves the right, upon written notice to Transmission Provider, to suspend
at any time all work by Transmission Provider associated with the construction and installation of Transmission Provider's Interconnection Facilities and/or Network Upgrades required under this LGIA with the condition that Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Provider's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Provider (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Provider cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Provider shall obtain Interconnection Customer's authorization to do so.

Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Transmission Provider required under this LGIA pursuant to this Article 5.16, and has not requested Transmission Provider to recommence the work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Transmission Provider, if no effective date is specified.

5.17 Taxes.

5.17.1 **Interconnection Customer Payments Not Taxable.** The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Provider for the installation of Transmission Provider's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 **Representations and Covenants.** In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to Transmission Provider for Transmission Provider's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of Transmission Provider's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to

IRS requirements for non-taxable treatment.

At Transmission Provider's request, Interconnection Customer shall provide Transmission Provider with a report from an independent engineer confirming its representation in clause (iii), above. Transmission Provider represents and covenants that the cost of Transmission Provider's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 **Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon the Transmission Provider.** Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Transmission Provider from the cost consequences of any current tax liability imposed against Transmission Provider as the result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Transmission Provider.

Transmission Provider shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this LGIA unless (i) Transmission Provider has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Transmission Provider should be reported as income subject to taxation or (ii) any Governmental Authority directs Transmission Provider to report payments or property as income subject to taxation; provided, however, that Transmission Provider may require Interconnection Customer to provide security for

Interconnection Facilities, in a form reasonably acceptable to Transmission Provider (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Transmission Provider for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Transmission Provider of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by Transmission Provider upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 **Tax Gross-Up Amount.** Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Interconnection Customer will pay Transmission Provider, in addition to the amount paid for the Interconnection Facilities and Network Upgrades, an amount equal to (1) the current taxes imposed on Transmission Provider ("Current Taxes") on the excess of (a) the gross income realized by Transmission Provider as a result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount")

over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit Transmission Provider to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Transmission Provider's composite federal and state tax rates at the time the payments or property transfers are received and Transmission Provider will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Transmission Provider's anticipated tax depreciation deductions as a result of such payments or property transfers by Transmission Provider's current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.17.5 Private Letter Ruling or Change or Clarification of Law. At Interconnection Customer's request and expense, Transmission Provider shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Transmission

Provider under this LGIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Transmission Provider and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Transmission Provider shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Transmission Provider shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 **Subsequent Taxable Events.** If, within 10 years from the date on which the relevant Transmission Provider's Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this LGIA terminates and Transmission Provider retains ownership of the Interconnection Facilities and Network Upgrades, Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Transmission Provider, calculated using the methodology described

in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 **Contests.** In the event any Governmental Authority determines that Transmission Provider's receipt of payments or property constitutes income that is subject to taxation, Transmission Provider shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Transmission Provider may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Transmission Provider reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Transmission Provider shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Transmission Provider may agree to a settlement either with Interconnection

Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Transmission Provider, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Transmission Provider for the tax at issue in the contest.

5.17.8 **Refund.** In the event that (a) a private letter ruling is issued to Transmission Provider which holds that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Transmission Provider in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not taxable to Transmission Provider, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Transmission Provider are not subject to federal income

tax, or (d) if Transmission Provider receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Transmission Provider pursuant to this LGIA, Transmission Provider shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by Interconnection Customer to Transmission Provider for such taxes which Transmission Provider did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Transmission Provider refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Transmission Provider, any refund or credit Transmission Provider receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to Transmission Provider for such overpayment of taxes (including any reduction in interest otherwise payable by Transmission Provider to any Governmental Authority resulting

from an offset or credit); provided, however, that Transmission Provider will remit such amount promptly to Interconnection Customer only after and to the extent that Transmission Provider has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to Transmission Provider's Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 **Taxes Other Than Income Taxes.** Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Provider for which Interconnection Customer may be required to reimburse Transmission Provider under the terms of this LGIA. Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Transmission Provider shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Transmission Provider for such

taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Provider.

5.17.10 Transmission Owners Who Are Not Transmission Providers. If Transmission Provider is not the same entity as the Transmission Owner, then (i) all references in this Article 5.17 to Transmission Provider shall be deemed also to refer to and to include the Transmission Owner, as appropriate, and (ii) this LGIA shall not become effective until such Transmission Owner shall have agreed in writing to assume all of the duties and obligations of Transmission Provider under this Article 5.17 of this LGIA.

5.18 Tax Status. Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this LGIA is intended to adversely affect any Transmission Provider's tax exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General. Either Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, that Party shall provide to the other Party sufficient information regarding such modification so that the other Party may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall

include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Large Generating Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Provider shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Provider's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 **Standards.** Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 **Modification Costs.** Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Provider makes to Transmission Provider's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Provider's Interconnection Facilities or the Transmission System, or to provide

transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

Article 6. Testing and Inspection

6.1 Pre-Commercial Operation Date Testing and Modifications. Prior to the Commercial Operation Date, Transmission Provider shall test Transmission Provider's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Large Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Large Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications. Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Large Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 Right to Observe Testing. Each Party shall notify the other Party in advance of its performance of tests of its Interconnection Facilities. The other Party has the right, at its own expense, to observe such testing.

6.4 Right to Inspect. Each Party shall have the right, but shall have no obligation to: (i) observe the other Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of the other Party's System Protection Facilities and other protective equipment; and (iii) review the other Party's maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. A Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Party. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this LGIA.

Article 7. Metering

7.1 General. Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Provider shall install Metering Equipment at the Point of Interconnection prior to any operation of the Large Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Large Generating Facility shall be measured at or, at Transmission Provider's option, compensated to, the Point of Interconnection. Transmission Provider shall provide metering quantities, in analog and/or digital form, to Interconnection Customer upon request. Interconnection Customer shall bear all

reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 **Check Meters.** Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Provider's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Provider or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 **Standards.** Transmission Provider shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

7.4 **Testing of Metering Equipment.** Transmission Provider shall inspect and test all Transmission Provider-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Transmission Provider shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than every two (2) years. Transmission Provider shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Provider's failure to maintain, then Transmission Provider shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission

Provider shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

7.5 Metering Data. At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Provider and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Large Generating Facility to the Point of Interconnection.

Article 8. Communications

8.1 Interconnection Customer Obligations. Interconnection Customer shall maintain satisfactory operating communications with Transmission Provider's Transmission System dispatcher or representative designated by Transmission Provider. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Large Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Provider as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Large Generating Facility to the location(s) specified by Transmission Provider. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation,

scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 **Remote Terminal Unit.** Prior to the Initial Synchronization Date of the Large Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Provider at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Provider through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Provider. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Provider.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 **No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4 **Provision of Data from a Variable Energy Resource.** The Interconnection Customer whose Generating Facility is a Variable Energy Resource shall provide meteorological and forced outage data to the Transmission Provider to the extent necessary for the Transmission Provider’s development and deployment of power production forecasts for that class of Variable Energy Resources. The Interconnection Customer with a Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, wind

speed, wind direction, and atmospheric pressure. The Interconnection Customer with a Variable Energy Resource having solar as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission Provider and Interconnection Customer whose Generating Facility is a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility is a Variable Energy Resource also shall submit data to the Transmission Provider regarding all forced outages to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Such requirements for meteorological and forced outage data are set forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

Article 9. Operations

9.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 **Control Area Notification**. At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider in

writing of the Control Area in which the Large Generating Facility will be located. If Interconnection Customer elects to locate the Large Generating Facility in a Control Area other than the Control Area in which the Large Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Control Area.

9.3 Transmission Provider Obligations. Transmission Provider shall cause the Transmission System and Transmission Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA. Transmission Provider may provide operating instructions to Interconnection Customer consistent with this LGIA and Transmission Provider's operating protocols and procedures as they may change from time to time. Transmission Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations. Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA. Interconnection Customer shall operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this LGIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Either Party may request that the other Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this LGIA.

9.5 Start-Up and Synchronization. Consistent with the Parties' mutually acceptable procedures, Interconnection Customer is responsible for the proper synchronization of the Large Generating Facility to Transmission Provider's Transmission System.

9.6 Reactive Power and Primary Frequency Response.

9.6.1 Power Factor Design Criteria. Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis. The requirements of this paragraph shall not apply to wind generators.

9.6.1.1 Synchronous Generation. Interconnection Customer shall design the Large Generating Facility to maintain a composite power deliver at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all synchronous generators in the Control Area on a comparable basis.

9.6.1.2 Non-Synchronous Generation. Interconnection Customer shall design the Large Generating Facility to maintain composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all non-synchronous generators in the Control Area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of the Final Rule establishing this requirement (Order No. 827).

9.6.2 **Voltage Schedules.** Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Transmission Provider shall require Interconnection Customer to operate the Large Generating Facility to produce or absorb reactive power within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Provider's voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. Transmission Provider shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance,

and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Large Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the System Operator.

9.6.2.1 Voltage Regulators. Whenever the Large Generating Facility is operated in parallel with the Transmission System and voltage regulators are capable of operation, Interconnection Customer shall operate the Large Generating Facility with its voltage regulators in automatic operation. If the Large Generating Facility's voltage regulators are not capable of such automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative, and ensure that such Large Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Large Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Large Generating

Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Control Area on a comparable basis.

9.6.3 **Payment for Reactive Power.** Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Large Generating Facility when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1, provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed.

9.6.4 Primary Frequency Response. Interconnection Customer shall ensure the primary frequency response capability of its Large Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term “functioning governor or equivalent controls” as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Large Generating Facility’s real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Large Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Large Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Large Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Large Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Interconnection Customer shall operate the Large Generating Facility consistent with the provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Large Generating Facilities.

9.6.4.1 Governor or Equivalent Controls. Whenever the Large Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Large Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Large Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Large Generating Facility's governor or equivalent controls to a minimum whenever the Large Generating Facility is operated in parallel with the Transmission System.

9.6.4.2 **Timely and Sustained Response.** Interconnection Customer shall ensure that the Large Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Large Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Large Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

9.6.4.3 **Exemptions.** Large Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement. Large Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 9.6.4, but shall be otherwise exempt from the operating requirements in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.4 of this Agreement.

9.6.4.4 **Electric Storage Resources.** Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Appendix C of its LGIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.3 of this Agreement. Appendix C shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Appendix C must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer’s electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 9.6.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination. Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to the Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Party of such removal.

9.7.1.2 Outage Schedules. Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Large Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

9.7.1.3 **Outage Restoration.** If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects the other Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Party, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

9.7.2 **Interruption of Service.** If required by Good Utility Practice to do so, Transmission Provider may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Provider;

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Large Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 **Under-Frequency and Over Frequency Conditions.** The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability of the Transmission System. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

9.7.4 **System Protection and Other Control Requirements.**

9.7.4.1 **System Protection Facilities.** Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or

Interconnection Customer's Interconnection Facilities. Transmission Provider shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Provider's Interconnection Facilities or the Transmission System as a result of the interconnection of the Large Generating Facility and Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

9.7.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 Requirements for Protection. In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Provider's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Large Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Large Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Large Generating Facility.

9.7.6 Power Quality. Neither Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

9.8 **Switching and Tagging Rules.** Each Party shall provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.9 **Use of Interconnection Facilities by Third Parties.**

9.9.1 **Purpose of Interconnection Facilities.** Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Transmission System and shall be used for no other purpose.

9.9.2 **Third Party Users.** If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Provider's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or Transmission Provider's Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

Article 10. Maintenance

10.1 Transmission Provider Obligations. Transmission Provider shall maintain the Transmission System and Transmission Provider's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.2 Interconnection Customer Obligations. Interconnection Customer shall maintain the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.3 Coordination. The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Large Generating Facility and the Interconnection Facilities.

10.4 **Secondary Systems.** Each Party shall cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Party. Each Party shall provide advance notice to the other Party before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

10.5 **Operating and Maintenance Expenses.** Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Provider's Interconnection Facilities.

Article 11. Performance Obligation

11.1 **Interconnection Customer Interconnection Facilities.** Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

11.2 **Transmission Provider's Interconnection Facilities.** Transmission Provider or Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Provider's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

11.3 Network Upgrades and Distribution Upgrades. Transmission Provider or Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades. The Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless Transmission Provider or Transmission Owner elects to fund the capital for the Network Upgrades, they shall be solely funded by Interconnection Customer. In the event that Transmission Provider must change the voltage levels of a discrete portion of the Transmission System to which the Interconnection Customer is connected, Transmission Provider shall give reasonable notice of such change and the Interconnection Customer shall be solely responsible for all costs related to upgrades or modifications to Interconnection Customer’s Interconnection Facilities resulting from Transmission Provider’s increase in the voltage levels of the Transmission System, in order to remain interconnected with the Transmission System at the new operating voltage. To the extent that the modifications necessary to upgrade Interconnection Facilities qualify as Network Upgrades, Transmission Provider shall be solely responsible for the expense of such modifications or upgrades.

11.4 Transmission Credits.

11.4.1 Repayment of Amounts Advanced for Network Upgrades. Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to Transmission Provider and Affected System Operator, if any, for the Network Upgrades, including any tax gross-up or other tax-related payments associated with Network Upgrades, and not refunded to Interconnection

Customer pursuant to Article 5.17.8 or otherwise, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Large Generating Facility. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC=s regulations at 18 C.F.R. § 35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. Interconnection Customer may assign such repayment rights to any person.

Notwithstanding the foregoing, Interconnection Customer, Transmission Provider, and Affected System Operator may adopt any alternative payment schedule that is mutually agreeable so long as Transmission Provider and Affected System Operator take one of the following actions no later than five years from the Commercial Operation Date: (1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or (2) declare in writing that Transmission Provider or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full reimbursement shall not extend beyond twenty (20) years from the Commercial Operation Date.

If the Large Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, Transmission Provider and Affected System Operator shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the Generating Facility, if different, is responsible for identifying the entity to which reimbursement must be made.

11.4.2 **Special Provisions for Affected Systems.** Unless Transmission Provider provides, under the LGIA, for the repayment of amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

11.4.3 Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Large Generating Facility.

11.5 Provision of Security. At least thirty (30) Calendar Days prior to the commencement of the first of the following to occur: design, procurement, installation, or construction of a discrete portion of a Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to Transmission Provider for these purposes.

In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must indicate that it would only expire upon final payment made to Transmission Provider to cover all relevant costs for designing, procuring, installing, and constructing the applicable portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which the letter of credit was provided.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must indicate that it would only expire upon final payment made to Transmission Provider to cover all relevant costs for designing, procuring, installing, and constructing the applicable portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which the surety bond was provided.

11.6 Interconnection Customer Compensation. If Transmission Provider requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this LGIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to an RTO or ISO FERC-approved rate schedule. Interconnection Customer shall serve Transmission Provider or RTO or ISO with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this LGIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

11.6.1 Interconnection Customer Compensation for Actions During Emergency Condition. Transmission Provider or RTO or ISO shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.6.

Article 12. Invoice

12.1 General. Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this LGIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice. Within six months after completion of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades, Transmission Provider shall provide an invoice of the final cost of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades and shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this LGIA.

12.4 Disputes. In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide Interconnection Service under this LGIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii).

Article 13. Emergencies

13.1 **Definition.** "Emergency Condition" shall mean a condition or situation: (i) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (ii) that, in the case of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, Transmission Provider's Interconnection Facilities or the Transmission Systems of others to which the Transmission System is directly connected; or (iii) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Large Generating Facility or Interconnection Customer's Interconnection Facilities' System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by this LGIA to possess black start capability.

13.2 **Obligations.** Each Party shall comply with the Emergency Condition procedures of the applicable ISO/RTO, NERC, the Applicable Reliability Council, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

13.3 **Notice.** Transmission Provider shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Provider's Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Transmission Provider promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Provider's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Provider's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

13.4 Immediate Action. Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Provider, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or otherwise regarding the Transmission System.

13.5 Transmission Provider Authority.

13.5.1 General. Transmission Provider may take whatever actions or inactions with regard to the Transmission System or Transmission Provider's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Provider's Interconnection

Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Large Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 **Reduction and Disconnection.** Transmission Provider may reduce Interconnection Service or disconnect the Large Generating Facility or Interconnection Customer's Interconnection Facilities, when such, reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of Transmission Provider pursuant to Transmission Provider's Tariff. When

Transmission Provider can schedule the reduction or disconnection in advance, Transmission Provider shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection Customer and Transmission Provider. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities, and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

13.6 Interconnection Customer Authority. Consistent with Good Utility Practice and the LGIA and the LGIP, Interconnection Customer may take actions or inactions with regard to the Large Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Provider's Interconnection Facilities. Transmission Provider shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.7 Limited Liability. Except as otherwise provided in Article 11.6.1 of this LGIA, neither Party shall be liable to the other for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

Article 14. Regulatory Requirements and Governing Law

14.1 Regulatory Requirements. Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this LGIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act, the Public Utility Holding Company Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

Article 15. Notices.

15.1 General. Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Either Party may change the notice information in this LGIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Party in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

Article 16. Force Majeure

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

Article 17. Default

17.1 Default

17.1.1 **General.** No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act of omission of the other Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 **Right to Terminate**. If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this LGIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this LGIA.

Article 18. Indemnity, Consequential Damages and Insurance

18.1 Indemnity. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this LGIA on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnified Party.

18.1.1 **Indemnified Person**. If an Indemnified Person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such Indemnified Person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 **Indemnifying Party**. If an Indemnifying Party is obligated to indemnify and hold any Indemnified Person harmless under this Article 18, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

18.1.3 **Indemnity Procedures**. Promptly after receipt by an Indemnified Person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Person shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the Indemnifying Party and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the Indemnifying Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses.

The Indemnified Person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the Indemnified Person and the Indemnifying Party, in such event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be reasonably withheld, conditioned or delayed.

18.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 Insurance. Each party shall, at its own expense, maintain in force throughout the period of this LGIA, and until released by the other Party, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this LGIA.

18.3.9 Within ten (10) days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, each Party shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

Article 19. Assignment

19.1 Assignment. This LGIA may be assigned by either Party only with the written consent of the other; provided that either Party may assign this LGIA without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this LGIA; and provided further that Interconnection Customer shall have the right to assign this LGIA, without the consent of Transmission Provider, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that Interconnection Customer will promptly notify Transmission Provider of any such assignment. Any financing arrangement entered into by Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured Party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider of the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

Article 20. Severability

20.1 Severability. If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental

Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Provider) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

Article 21. Comparability

21.1 **Comparability.** The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

Article 22. Confidentiality

22.1 **Confidentiality.** Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 **Term.** During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 **Scope.** Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of the LGIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

22.1.3 **Release of Confidential Information.** Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 **Rights**. Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 **No Warranties**. By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 **Standard of Care**. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this LGIA or its regulatory requirements.

22.1.7 **Order of Disclosure.** If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this LGIA.

Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 **Termination of Agreement.** Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

22.1.9 **Remedies.** The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 **Disclosure to FERC, its Staff, or a State**. Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 CFR section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this LGIA prior to the release of the Confidential Information to FERC or its staff. The

Party shall notify the other Party to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this LGIA ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

Article 23. Environmental Releases

23.1 Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

Article 24. Information Requirements

24.1 **Information Acquisition**. Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 **Information Submission by Transmission Provider**. The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 Updated Information Submission by Interconnection Customer. The updated information submission by Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Trial Operation. Interconnection Customer shall submit a completed copy of the Large Generating Facility data requirements contained in Appendix 1 to the LGIP. It shall also include any additional information provided to Transmission Provider for the Feasibility and Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study Agreement between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on Transmission Provider Transmission System based on the actual data submitted pursuant to this Article 24.3. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

24.4 Information Supplementation. Prior to the Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Large Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Large Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Large Generating Facility to verify proper operation of the Large Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Large Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent change in Large Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Large Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Large Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Large Generating Facility terminal or field voltages is provided. Large Generating Facility testing shall be conducted and results provided to Transmission Provider for each individual generating unit in a station.

Subsequent to the Operation Date, Interconnection Customer shall provide Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Provider shall provide Interconnection Customer any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Provider-owned substation that may affect Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

Article 25. Information Access and Audit Rights

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Party information that is in the possession of the disclosing Party and is necessary in order for the other Party to: (i) verify the costs incurred by the disclosing Party for which the other Party is responsible under this LGIA; and (ii) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA.

25.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Party when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this LGIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this LGIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party, to audit at its own expense the other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this LGIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this LGIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of Transmission Provider's Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission Provider's issuance of a final invoice in accordance with Article 12.2.

25.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to either Party's performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

25.5 Audit Results. If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

Article 26. Subcontractors

26.1 General. Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

26.2 Responsibility of Principal. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Provider be liable for the actions or inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

Article 27. Disputes

27.1 Submission. In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 External Arbitration Procedures. Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail.

27.3 Arbitration Decisions. Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

27.4 Costs. Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

Article 28. Representations, Warranties, and Covenants

28.1 General. Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 Authority. Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 **No Conflict**. The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 **Consent and Approval**. Such Party has sought or obtained, or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

Article 29. Joint Operating Committee

29.1 Joint Operating Committee. Except in the case of ISOs and RTOs, Transmission Provider shall constitute a Joint Operating Committee to coordinate operating and technical considerations of Interconnection Service. At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Interconnection Customer shall notify Transmission Provider of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of either Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this LGIA. Each Party shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

29.1.1 Establish data requirements and operating record requirements.

29.1.2 Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

29.1.3 Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Provider's and Interconnection Customer's facilities at the Point of Interconnection.

29.1.4 Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Large Generating Facility and other facilities that impact the normal operation of the interconnection of the Large Generating Facility to the Transmission System.

29.1.5 Ensure that information is being provided by each Party regarding equipment availability.

29.1.6 Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

Article 30. Miscellaneous

30.1 Binding Effect. This LGIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts. In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation. This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix to this LGIA, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 Entire Agreement. This LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this LGIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this LGIA.

30.5 No Third Party Beneficiaries. This LGIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 Waiver. The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party. Any waiver at any time by either Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this LGIA. Termination or Default of this LGIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 Headings. The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

30.8 Multiple Counterparts. This LGIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment. The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by the Parties.

30.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. Transmission Provider shall have the right to make a unilateral filing with FERC to modify this LGIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

IN WITNESS WHEREOF, the Parties have executed this LGIA in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

PACIFICORP, on behalf of its Transmission function

By: ______________________
Rick Vail
Title: VP, Transmission

Date: 2/19/2019

PACIFICORP, on behalf of its Marketing function (Q707)

By: ______________________

Title: SVP, Bus. Policy & Development

Date: Feb. 15, 2019

Appendix A to LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

1. Interconnection Facilities:

(a) **Interconnection Customer's Interconnection Facilities:** Three (3) circuit breakers (one per step up transformer) connected to a short generator tie line for the Interconnection Customer collector substation to the Point of Interconnection (Shirley Basin) substation. Please see Exhibit 1 to Attachment A.

(b) **Transmission Provider's Interconnection Facilities:** Three (3) production meters located at the high side of the step up transformers at the Interconnection Customer collector substation as well as relaying and communications equipment, one (1) interchange meter at the Point of Change of Ownership, and one line position (dead end structure, disconnect switch, metering structure) located at the Point of Interconnection (Shirley Basin) substation. Please see Exhibit 1 to Attachment A.

2. Network Upgrades:

(a) **Stand Alone Network Upgrades:** None

(b) **Other Network Upgrades:** Five (5) new breakers and corresponding bus and relaying at Shirley basic substation, New line position at Aeolus substation for new transmission line from Shirley Basin substation, and new line from Shirley Basin to Aeolus substation.

3. Distribution Upgrades: None

4. Contingent Facilities: As identified in the System Impact Study for this project dated August 21, 2018 the following Network Upgrades are required to be in-service prior to this project:

- Segment D2 (500 kV line Aeolus-Anticline/Bridger). (Transmission Provider internal, 2020)

- A Remedial Action Scheme (“RAS”) for various 500 kV outages. (Transmission Provider internal, 2020)

If the schedule for completion of these upgrades changes the Transmission Provider reserves the right to restudy this project to determine any additional requirements to assign to this project necessary to facilitate interconnection of this project by the date required.

5. Point of Interconnection (“POI”): The point at which Transmission Provider Interconnection Facilities connect to the substation bus at the Shirley Basin substation (see Exhibit 1 to Appendix A).

6. Point of Change of Ownership: The point at which Interconnection Customer and Transmission Provider Interconnection Facilities meet (see Exhibit 1 to Appendix A)

7. One-Line Diagram: is attached to this agreement as Exhibit 1 to Appendix A.

8. **Estimated Project Cost:** $26,896,000
Direct Assigned: $1,660,000
Network Upgrade: $25,236,000

Appendix B To LGIA

Milestones

Milestone	**Party**
Execute Interconnection Agreement January 23, 2019	Interconnection Customer
Provision of Financial Security ($5,160,000) January 23, 2019	Interconnection Customer
Design Information Provided January 23, 2019	Interconnection Customer
Property/Permits/ROW Procured February 1, 2019	Interconnection Customer
Provide construction approval April 1, 2019	Interconnection Customer
**Energy Imbalance Market Modeling Data Submittal April 10, 2019	Interconnection Customer
Engineering Design Complete April 10, 2019	Transmission Provider
Construction Begins May 1, 2019	Transmission Provider
Facilities Receive Backfeed Power June 15, 2020	Interconnection Customer
***Contingent facilities complete October 1, 2020	Transmission Provider
Initial Synchronization and Generation Testing October 1, 2020	Interconnection Customer
Commercial Operation November 1, 2020	Interconnection Customer

*As applicable and determined by the Transmission Provider, within 60 days of the Interconnection Customer’s authorization for the Transmission Provider to begin engineering, the Interconnection Customer shall provide a detailed short circuit model of its generation system. This model must be constructed using the ASPEN One-Line short circuit simulation program and contain all individual electrical components of the Interconnection Customer's generation system.

**Any design modifications to the Interconnection Customer's Generating Facility after this date requiring updates to the Transmission Provider's network model will result in a minimum of 3 months added to all future milestones including Commercial Operation.

***Delays in completion of Contingent Facilities will impact the in-service date of the project.

Term of Agreement: In accordance with LGIA Article 2.2, the Parties agree that the term of the LGIA shall be ten (10) years from the Effective Date and shall be automatically renewed for each successive one-year period thereafter.

Construction Option: The Network Upgrades, Direct Assignment Facilities and Transmission Provider Interconnection Facilities will be designed, procured and constructed by the Transmission Provider in accordance with the Standard Option outlined in Article 5.1.1 of this Agreement. The Network Upgrades, Direct Assignment Facilities and Transmission Provider Interconnection Facilities shall be constructed in accordance with the Scope of Work attached to this LGIA as Exhibit 1 to Appendix B. The Network Upgrades, Direct Assignment Facilities and Transmission Provider's Interconnection Facilities shall be designed, procured and constructed in a timely manner to support the Milestone Dates stated above.

Appendix C To LGIA

Interconnection Details

Description of the Large Generating Facility: The Large Generating Facility consists of fourteen (14) Vestas V110 2.0 and fifty-three (53) Vestas V136 4.3 turbines connected to twelve (12) 34.5 kV strings for a total generation output of 250 MW as measured at the POI. The strings are then connected to a three (in parallel) 75/100/125 MVA 34.5 – 230 kV (7.5% impedance) transformers. The Large Generating Facility is located in Carbon County, Wyoming.

Please see Exhibit 1 to Attachment A.

Control Area Requirements: Interconnection Customer shall interconnect and operate the Large Generating Facility in accordance with the Transmission Provider's Facility Interconnection Requirements for Transmission Systems, as may be revised from time to time, attached hereto as Exhibit 1 to Appendix C and by this reference incorporated herein.

Interconnection Details:
Metering. With reference to Article 7.1, Transmission Provider will own and maintain the bi-directional revenue Metering Equipment in Transmission Provider's Point of Interconnection substation at the Interconnection Customer's expense.

Under Frequency and Over Frequency Conditions. Consistent with LGIA Article 9.7.3, Transmission Provider shall design, procure, install and maintain frequency and voltage protection to trip feeder breakers in accordance with the settings shown in Exhibit 1 to Appendix C.

Reactive Power and Voltage Schedule. All interconnecting synchronous and non-synchronous generators are required to design their Generating Facilities with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices. For non-synchronous generators, the power factor requirement is to be measured at the high-side of the generator substation. The Generating Facility must provide dynamic reactive power to the system over the full range of real power output. If the Generating Facility is not capable of providing positive reactive support (i.e., supplying reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations, the facility will be required to add dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.

Generators shall be equipped with automatic voltage-control equipment and normally operated with the voltage regulation control mode enabled unless written authorization, or directive, from the Transmission Provider is given to operate in another control mode (e.g., constant power factor control). The control mode of generating units shall be accurately represented in operating studies. The generators shall be capable of operating continuously at their rated power output within +/- 5% of its rated terminal voltage. Phasor Measurement Units will be required at any Generating Facilities with an individual or aggregate nameplate capacity of 75 MVA or greater.

As required by NERC standard VAR-001-1a, the Transmission Provider will provide a voltage schedule for the Point of Interconnection. In general, Generating Facilities should be operated so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Transmission Provider, in accordance with Transmission Provider Policy 139.

Generating Facilities capable of operating with a voltage droop are required to do so. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer’s responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing. If the need for a master controller is identified, the cost and all related installation requirements will be the responsibility of the Interconnection Customer. Participation by the Generation Facility in subsequent interaction/coordination studies will be required pre- and post-commercial operation in order ensure system reliability.

All generators must meet the Federal Energy Regulatory Commission (FERC) and WECC low voltage ride-through requirements.

As the Transmission Provider cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

Property Requirements. Subject to LGIA Articles 5.12 and 5.13, Interconnection Customer is required to obtain for the benefit of Transmission Provider at Interconnection Customer's sole cost and expense all real property rights, including but not limited to fee ownership, easements and/or rights of way, as applicable, for Transmission Provider owned facilities using forms acceptable to Transmission Provider. Transmission Provider shall not be obligated to accept any such real property right that does not, at Transmission Provider's sole discretion, confer sufficient rights to access, operate, construct, modify, maintain, place and remove Transmission Provider owned facilities or is otherwise conveyed using forms unacceptable to Transmission Provider. Further, all real property on which Transmission Provider's facilities are to be located must be environmentally, physically and operationally acceptable to the Transmission Provider in accordance with Good Utility Practice.

Subject to LGIA Article 5.14, Interconnection Customer is responsible for obtaining all permits required by all relevant jurisdictions for the project, including but not limited to, conditional use permits and construction permits; provided however, Transmission Provider shall obtain, at Interconnection Customer's cost and schedule risk, the permits necessary to construct Transmission Provider's facilities that are to be located on real property currently owned or held in fee or right by Transmission Provider.

Subject to applicable provisions in the Agreement and an express written waiver by an authorized officer of Transmission Provider, all of the foregoing permits and real property rights (conferring rights on real property that is environmentally, physically and operationally acceptable to Transmission Provider) shall be acquired as provided herein as a condition to Transmission Provider's contractual obligation to construct or take possession of facilities to be owned by the Transmission Provider under this Agreement. Transmission Provider shall have no liability for any project delays or cost overruns caused by delays in acquiring any of the foregoing permits and/or real property rights, whether such delay results from the failure to obtain such permits or rights or the failure of such permits or rights to meet the requirements set forth herein. Further, any completion dates, if any, set forth herein with regard to Transmission Provider's obligations shall be equitably extended based on the length and impact of any such delays.

With respect to the fiber optic cable on Interconnection Customer's tie line that will be owned by the Transmission Provider, the Interconnection Customer and the Transmission Provider agree that Transmission Provider's ownership and operation of fiber optic cable that is attached to poles or other structures that are owned or maintained by the Interconnection Customer is subject to LGIA Article 5.12, Good Utility Practice, and Transmission Provider's Interconnection Policy 139 (Exhibit 1 to Appendix C to LGIA).

Appendix D To LGIA

Security Arrangements Details

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

Automatic Data Transfer. Throughout the term of this Agreement, Interconnection Customer shall provide the data specified below by automatic data transfer to the Transmission Provider Control Center specified by Transmission Provider or to a Third-Party System Operator designated by Transmission Provider (or both):

From the Interconnection Customer’s collector substation:

- Analogs:
  - Transformer # 1 real power
  - Transformer # 1 reactive power
  - Real power flow through 34.5 kV line feeder breaker 1
  - Reactive power flow through 34.5 kV line feeder breaker 1
  - Real power flow through 34.5 kV line feeder breaker 2
  - Reactive power flow through 34.5 kV line feeder breaker 2
  - Real power flow through 34.5 kV line feeder breaker 3
  - Reactive power flow through 34.5 kV line feeder breaker 3
  - Real power flow through 34.5 kV line feeder breaker 4
  - Reactive power flow through 34.5 kV line feeder breaker 4

- o Real power flow through 34.5 kV line feeder breaker 5
- o Reactive power flow through 34.5 kV line feeder breaker 5
- o Reactive power flow through 34.5 kV reactor breaker T1-R1
- o Reactive power flow through 34.5 kV capacitor breaker T1-C1
- o Transformer # 2 real power
- o Transformer # 2 reactive power
- o Real power flow through 34.5 kV line feeder breaker 6
- o Reactive power flow through 34.5 kV line feeder breaker 6
- o Real power flow through 34.5 kV line feeder breaker 7
- o Reactive power flow through 34.5 kV line feeder breaker 7
- o Real power flow through 34.5 kV line feeder breaker 8
- o Reactive power flow through 34.5 kV line feeder breaker 8
- o Real power flow through 34.5 kV line feeder breaker 9
- o Reactive power flow through 34.5 kV line feeder breaker 9
- o Real power flow through 34.5 kV line feeder breaker 10
- o Reactive power flow through 34.5 kV line feeder breaker 10
- o Reactive power flow through 34.5 kV reactor breaker T2-R1
- o Reactive power flow through 34.5 kV capacitor breaker T2-C1
- o Transformer # 3 real power
- o Transformer # 3 reactive power
- o Real power flow through 34.5 kV line feeder breaker 11
- o Reactive power flow through 34.5 kV line feeder breaker 11
- o Real power flow through 34.5 kV line feeder breaker 12
- o Reactive power flow through 34.5 kV line feeder breaker 12
- o Reactive power flow through 34.5 kV reactor breaker T3-R1

   - o Reactive power flow through 34.5 kV capacitor breaker T3-C1
   - o Average Plant Wind speed
   - o Average Plant Atmospheric Pressure (Bar)
   - o Average Plant Temperature (Celsius)
- Status:
   - o 230 kV breaker T1
   - o 34.5 kV collector circuit breaker 1
   - o 34.5 kV collector circuit breaker 2
   - o 34.5 kV collector circuit breaker 3
   - o 34.5 kV collector circuit breaker 4
   - o 34.5 kV collector circuit breaker 5
   - o 34.5 kV reactor circuit breaker T1-R1
   - o 34.5 kV capacitor circuit breaker T1-C1
   - o 230 kV breaker T2
   - o 34.5 kV collector circuit breaker 6
   - o 34.5 kV collector circuit breaker 7
   - o 34.5 kV collector circuit breaker 8
   - o 34.5 kV collector circuit breaker 9
   - o 34.5 kV collector circuit breaker 10
   - o 34.5 kV reactor circuit breaker T2-R1
   - o 34.5 kV capacitor circuit breaker T2-C1
   - o 230 kV breaker T3
   - o 34.5 kV collector circuit breaker 11
   - o 34.5 kV collector circuit breaker 12
   - o 34.5 kV reactor circuit breaker T3-R1
   - o 34.5 kV capacitor circuit breaker T3-C1

Billing Meter Data. Bi-directional revenue meter at the Point of Interconnection will not be configured to allow direct dial-up access by Interconnection Customer. The Transmission Provider will provide alternatives, at the Interconnection Customer’s expense, upon request.

Additional Data. Interconnection Customer shall, at its sole expense, provide any additional Generating Facility data reasonably required and necessary for the Transmission Provider to operate the Transmission System in accordance with Good Utility Practice and Exhibit 1 to Appendix C, Facility Interconnection Requirements for Transmission Systems.

Relay and Control Settings

If Interconnection Customer requires modifications to the settings associated with control/protective devices connected to the distribution and/or transmission system, Interconnection Customer will contact PacifiCorp and provide in writing the justification for the proposed modifications. This will allow PacifiCorp to analyze the modifications and ensure there will be no negative impacts to connected systems and customers. Any modifications of control and/or relay settings without review and acknowledgement of acceptance by PacifiCorp will be considered a breach of the Interconnection Agreement and grounds for disconnection from the PacifiCorp system.

Appendix E To LGIA

Commercial Operation Date

This Appendix E is a part of the LGIA between Transmission Provider and Interconnection Customer.

[Date]

[Transmission Provider Address]

Re: _______________ Large Generating Facility

Dear _______________:

On **[Date] [Interconnection Customer]** has completed Trial Operation of Unit No. __. This letter confirms that [Interconnection Customer] commenced Commercial Operation of Unit No. ___ at the Large Generating Facility, effective as of **[Date plus one day]**.

Thank you.

[Signature]

[Interconnection Customer Representative]

Appendix F to LGIA

Addresses for Delivery of Notices and Billings

Notices, Billings and Payments:

Transmission Provider:

US Mail Deliveries: PacifiCorp Transmission Services
Attn: Central Cashiers Office
PO Box 2757
Portland, OR 97208-2757

Other Deliveries: Central Cashiers Office
Attn: PacifiCorp Transmission Services
825 NE Multnomah Street, Suite 550
Portland OR 97232

Phone Number: 503-813-6774

Interconnection Customer:
PacifiCorp
Attn: Mike Saunders
1407 W North Temple
Salt Lake City, UT 84116

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

Director, Transmission Services	503-813-7237
Manager, Transmission Scheduling	503-813-5342
Director, Interconnection Services	503-813-6496
Transmission Business Facsimile	503-813-6893

OASIS Address:
http://www.oasis.pacificorp.com/oasis/ppw/main.htmlx

Interconnection Customer:
PacifiCorp
Attn: Mike Saunders
Telephone: 801-220-4869
Mobile: 909-560-0917
Email: Michael.Saunders@pacificorp.com

Appendix G to LGIA

INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating

plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or “GSU”), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the

fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. Power Factor Design Criteria (Reactive Power)

The following reactive power requirements apply only to a newly interconnecting wind generating plant that has executed a Facilities Study Agreement as of the effective

date of the Final Rule establishing the reactive power requirements for non-synchronous generators in section 9.6.1 of this LGIA (Order No. 827). A wind generating plant to which this provision applies shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

Exhibit 1 to Appendix A to LGIA

One-Line Diagram

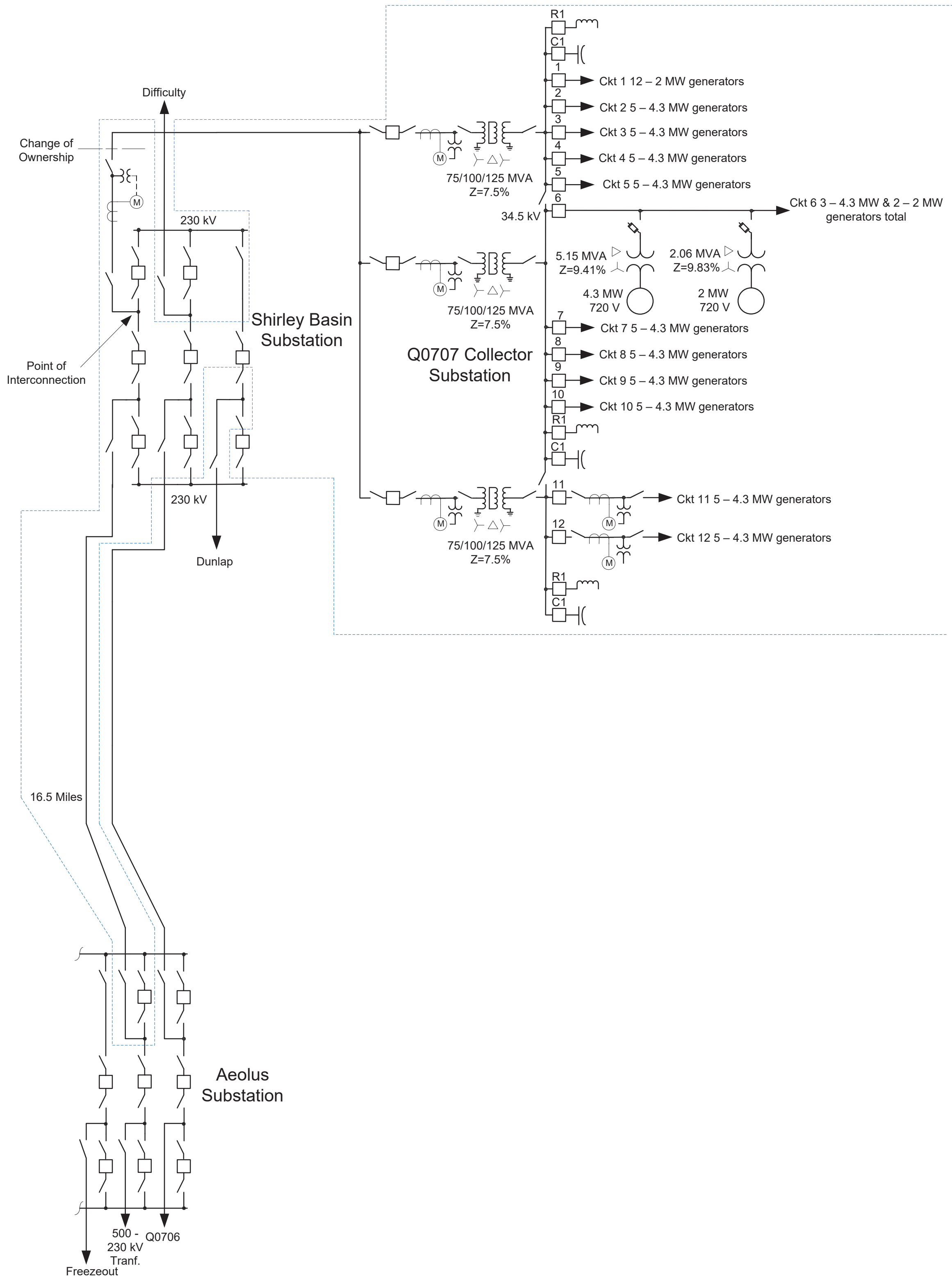


Exhibit 1 to Appendix B to LGIA

Scope of Work

Generating Facility Modifications

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer’s Generation Facility.

Interconnection Customer to be Responsible For

- Procure all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the Large Generating Facility and collector substation.
- Design, procure, construct, own and maintain the Interconnection Customer’s collector substation adjacent (less than 800’) to the POI substation. The segment between the collector substation and the POI substation will be considered a bus section and will be protected with redundant bus differential relay systems. The bus differential relays will be located in the POI substation.
- Design the Generating Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer’s GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the generating facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Generating Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Transmission Provider.

- Install a Phasor Measurement Unit to collect data from the Project. The data must be collected and be able to stream to the Planning Coordinator for each of the Generator Facility's step-up transformers measured on the low side of the GSU at a sample rate of at least 30 samples per second and synchronized within +/- 2 milliseconds of the Coordinated Universal Time (UTC). Initially, the following data must be collected:
  - o Three phase voltage and voltage angle (analog)
  - o Three phase current (analog)

  Data requirements are subject to change as deemed necessary to comply with local and federal regulations.
- Operate the Generating Facility so as to maintain the voltage at the POI, or other designated point as deemed appropriate by Transmission Provider, at a voltage schedule to be provided by the Transmission Provider following testing.
- Operate the Generating Facility with a voltage droop.
- Participate in any Transmission Provider required studies, such as a voltage coordination study. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Meet the Federal Energy Regulatory Commission (FERC) and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide the Transmission Provider a standard model from the WECC Approved Dynamic Model Library.
- Design the collector substation such that the ground grid can be connected to the POI substation ground grid to support the installation of a Transmission Provider owned and maintained bus differential scheme. The Interconnect Customer is responsible to ensure the ground grid design supports safe step and touch potentials.
- Design, provide and install conduits between the Interconnection Customer collector substation and the marshalling cabinet just inside the fence of the POI substation to support hard-wired circuits installed between the facilities.
- Design, provide and install control cabling (number and size TBD) and hard wire the Interconnection Customer's source devices to the marshalling cabinet. Replicated values are not acceptable.

- Provide and install complete conduit system, as designed by Transmission Provider, from each Transmission Provider metering instrument transformer to the POI substation marshalling cabinet just inside the fence of the POI substation.
- Provide and install complete conduit system, as designed by Transmission Provider, from each Transmission Provider metering instrument transformer to the POI substation marshalling cabinet just inside the fence of the POI substation.
- Install two sets of current transformers ("CT") from the 230 kV transformers and provide the output to be fed into the Transmission Provider's bus differential relays with current transformer ratio matching the CT ratio of the breakers at the POI substation.
- Provide the following data points from the collector substation via hardwire to the marshalling cabinet located in the POI substation:

  Analogs:

  - Transformer # 1 real power
  - Transformer # 1 reactive power
  - Real power flow through 34.5 kV line feeder breaker 1
  - Reactive power flow through 34.5 kV line feeder breaker 1
  - Real power flow through 34.5 kV line feeder breaker 2
  - Reactive power flow through 34.5 kV line feeder breaker 2
  - Real power flow through 34.5 kV line feeder breaker 3
  - Reactive power flow through 34.5 kV line feeder breaker 3
  - Real power flow through 34.5 kV line feeder breaker 4
  - Reactive power flow through 34.5 kV line feeder breaker 4
  - Real power flow through 34.5 kV line feeder breaker 5
  - Reactive power flow through 34.5 kV line feeder breaker 5
  - Reactive power flow through 34.5 kV reactor breaker T1-R1
  - Reactive power flow through 34.5 kV capacitor breaker T1-C1
  - Transformer # 2 real power
  - Transformer # 2 reactive power

- Real power flow through 34.5 kV line feeder breaker 6
- Reactive power flow through 34.5 kV line feeder breaker 6
- Real power flow through 34.5 kV line feeder breaker 7
- Reactive power flow through 34.5 kV line feeder breaker 7
- Real power flow through 34.5 kV line feeder breaker 8
- Reactive power flow through 34.5 kV line feeder breaker 8
- Real power flow through 34.5 kV line feeder breaker 9
- Reactive power flow through 34.5 kV line feeder breaker 9
- Real power flow through 34.5 kV line feeder breaker 10
- Reactive power flow through 34.5 kV line feeder breaker 10
- Reactive power flow through 34.5 kV reactor breaker T2-R1
- Reactive power flow through 34.5 kV capacitor breaker T2-C1
- Transformer # 3 real power
- Transformer # 3 reactive power
- Real power flow through 34.5 kV line feeder breaker 11
- Reactive power flow through 34.5 kV line feeder breaker 11
- Real power flow through 34.5 kV line feeder breaker 12
- Reactive power flow through 34.5 kV line feeder breaker 12
- Reactive power flow through 34.5 kV reactor breaker T3-R1
- Reactive power flow through 34.5 kV capacitor breaker T3-C1
- Average Plant Wind speed
- Average Plant Atmospheric Pressure (Bar)
- Average Plant Temperature (Celsius)

Status:

- 230 kV breaker T1
- 34.5 kV collector circuit breaker 1
- 34.5 kV collector circuit breaker 2
- 34.5 kV collector circuit breaker 3
- 34.5 kV collector circuit breaker 4

  - o 34.5 kV collector circuit breaker 5
  - o 34.5 kV reactor circuit breaker T1-R1
  - o 34.5 kV capacitor circuit breaker T1-C1
  - o 230 kV breaker T2
  - o 34.5 kV collector circuit breaker 6
  - o 34.5 kV collector circuit breaker 7
  - o 34.5 kV collector circuit breaker 8
  - o 34.5 kV collector circuit breaker 9
  - o 34.5 kV collector circuit breaker 10
  - o 34.5 kV reactor circuit breaker T2-R1
  - o 34.5 kV capacitor circuit breaker T2-C1
  - o 230 kV breaker T3
  - o 34.5 kV collector circuit breaker 11
  - o 34.5 kV collector circuit breaker 12
  - o 34.5 kV reactor circuit breaker T3-R1
  - o 34.5 kV capacitor circuit breaker T3-C1
- Provide and install conductor, shield wire and line hardware in sufficient quantities to allow the Transmission Provider to terminate the segment running from the collector substation deadend structure into the POI substation deadend structure.
- Provide Transmission Provider unfettered and maintained access to all of the Transmission Provider’s metering instrument transformers.
- Arrange for and provide permanent retail service for power that will flow from the Transmission Provider’s system when the Project is not generating with the retail service provider in this area. This will require the retail service provider to obtain transmission service from the Transmission Provider. These arrangements must be in place prior to approval for backfeed.
- Provide any construction or backup retail service necessary for the Project.
- The Transmission Provider recommends that the Interconnection Customer perform special studies and provide documentation that its turbines have been equipped with SSCI functionality.

TRANSMISSION PROVIDER TO BE RESPONSIBLE FOR

- Provide the Interconnection Customer the designated point at which the voltage is to be maintained and the associated voltage schedule.
- Identify any necessary studies that the Interconnection Customer must participate in.
- Identify the values to be stored in the PMU.

- Procure, install, own and maintain 230 kV instrument transformers on the high side of each of the three Interconnection Customer step up transformers.
- Procure, install, own and maintain 34.5 kV instrument transformers on the low side of the Interconnection Customer step up transformer 3 on circuits 11 and 12.
- Design complete conduit and control cable from each Transmission Provider metering instrument transformer to the POI substation marshalling cabinet just inside the fence of the POI substation.
- Install metering control cable in metering conduit system installed by Interconnection Customer.

Point of Interconnection

The following outlines the design, procurement, construction, installation, and ownership of equipment at the POI.

Interconnection Customer to be Responsible For

- Assist the Transmission Provider as necessary in the procurement of any property rights necessary to expand the substation.

Transmission Provider to be Responsible For

- Procure all necessary permits, property rights and/or rights of way to allow for the expansion of the substation.
- Expand the existing substation to allow for the breaker and a half scheme to be completed and to create two new line positions.
- Design, procure, construct, own and maintain the following major equipment:
  - (7) – 230kV circuit breakers
  - (5) – 230kV, CCVT's
  - (3) – 230 kV, combined CT/VT metering unit
  - (15) – 230kV, switch, breaker disconnect
  - (3) – 230 kV, switch, line disconnect
  - (1) – 230 kV, switch, meter disconnect
  - (6) – 230kV, surge arresters
  - (1) – Marshalling cabinet
- Terminate the new transmission line running from Aeolus substation in a new line position.
- Terminate the last bus/line segment running from the Interconnection Customer's collector substation deadend structure into the POI substation deadend

structure using Interconnection Customer provided and installed conductor, shield wire and line hardware.

- Procure and install a marshalling cabinet near the Interconnection Customer's collector substation.
- Provide and install conduit and control cabling between the marshalling cabinet and the control building and bus differential cabinet.
- Design, procure and install two bus differential relay systems for the connection to the Interconnection Customer's collector substation.
- Modify existing relay elements to monitor under/over voltage and over/under frequency of the Generating Facility.
- Procure and install a line current differential relay system for protection of the new transmission line to Aeolus substation.
- Reconnect the relays installed for protection of the transmission line running to Dunlap substation to the new 230 kV circuit breakers.
- Include all the data points provided by the Interconnection Customer from its collector substation as well as the following data points from the new POI substation into the new substation RTU:
  Analogs:
  - o New Generation MW
  - o Net Generator MVAr
  - o Energy Register
- Provide and install fiber between the control building and the OPGW to be installed on the new transmission line running to Aeolus substation. Terminate the fiber in the control building communications rack.
- Design, procure and install revenue metering equipment to serve as the overall Project interchange metering including two (2) revenue quality meters, test switch, 230 kV instrument transformers, metering panels, junction box and secondary metering wire.
- Design, procure and install three sets of 230 kV revenue metering equipment for each of the Interconnection Customer's step up transformers including two revenue quality meters, test switches, metering panels, junction box and secondary metering wire for each transformer.
- Design, procure and install two sets of 34.5 kV revenue metering equipment for the Interconnection Customer's circuits 11 and 12 including two revenue

quality meters, test switches, metering panels, junction box and secondary metering wire for each transformer.

- Design, provide, and install the control cabling running from the five sets of instrument transformers installed in the Interconnection Customer's collector substation.
- If requested, install a metering cabinet on the exterior of the POI substation fence in order to provide a Modbus or DNP output from the bidirectional meters to the retail service provider. The Transmission Provider will install an underground communication wire from the POI substation control building to the meter panel.
- Establish an Ethernet connection for retail sales and generation accounting via the MV-90 translation system.

Other

The following outlines the design, procurement, construction, installation, and ownership of equipment past the POI.

Transmission Provider to be Responsible For

- Aeolus-Shirley Basin #2 Transmission Line
  - o Procure any necessary rights of way, easements and/or permits to allow the construction of a new transmission line between Shirley Basin and Aeolus substation.
  - o Construct, own and maintain an approximately 16.5 mile 230 kV transmission line using double bundled 1158.4 ACSS/TW (Hudson) conductor between Shirley Basin and Aeolus substations.
  - o Install, own and maintained OPGW fiber optic cable on the entire length of the transmission line.
- Aeolus Substation
  - o Procure and install the necessary equipment to create a new line position for the line running from Shirley Basin substation including the following major equipment:
    - (1) – 230kV, circuit breaker
    - (3) – 230kV, CCVT's
    - (2) – 230kV, switch, breaker disconnect
    - (1) – 230 kV, switch, line disconnect
    - (3) – 230kV, surge arresters
  - o Terminate the new transmission line running from Shirley Basin substation in the new line position.

  - Procure and install a line current differential relay system for protection of the new transmission line to Shirley Basin substation.
  - Procure and install the necessary communication equipment to tie in the OPGW as well as to support protective relaying.
  - Provide and install fiber between the control building and the OPGW to be installed on the new transmission line running to Shirley Basin substation. Terminate the fiber in the control building communications rack.
- Remedial Action Scheme
  - Make the necessary adjustments to the Aeolus RAS assumed to be developed as part of an earlier queued project to add the Project. The Project will be tripped for various 500 kV outage scenarios associated with the Transmission Provider's planned Gateway West and Gateway South transmission lines. The RAS master controller will be installed in Aeolus substation. Primary communications to the Project will be on the existing fiber optic cable installed on the Aeolus-Shirley Basin #1 transmission line. The redundant communication will be on the new fiber optic cable on the Aeolus-Shirley Basin #2 transmission line.
  - If necessary, present for approval any generator tripping/load reduction schemes to the WECC Remedial Action Scheme Reliability Subcommittee ("RASRS").
- System Operations Centers
  - Update databases of the inclusion of the Project.

Exhibit 1 to Appendix C to LGIA

Facility Connection Requirements for Transmission Systems

(see attached)

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Transmission Services

STANDARD LARGE GENERATOR

INTERCONNECTION AGREEMENT (LGIA)
between
PACIFICORP, on behalf of its Transmission function
and
PACIFICORP, on behalf of its Marketing function
TB Flats II – Q708

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STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this 19th day of February, 20 19 by and between PacifiCorp, on behalf of its Marketing function, a corporation organized and existing under the laws of the State of Oregon ("Interconnection Customer") with a Large Generating Facility), and PacifiCorp, on behalf of its Transmission function, a corporation organized and existing under the laws of the State of Oregon ("Transmission Provider and/or Transmission Owner"). Interconnection Customer and Transmission Provider each may be referred to as a "Party" or collectively as the "Parties."

Recitals

WHEREAS, Transmission Provider operates the Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and,

WHEREAS, Interconnection Customer and Transmission Provider have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility with the Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (Tariff).

Article 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection System Impact Study.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or

Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not

include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission

Provider's Transmission System. The scope of the study is defined in Section 43 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System, the scope of which is described in Section 41 of the Standard Large Generator Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility

pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

NERC shall mean the North American Electric Reliability Council or its successor organization.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of

constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose.

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in the Transmission Provider's Tariff.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission Provider's Transmission System or on other delivery systems or other generating systems to which the Transmission Provider's Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC,

and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Large Generator Interconnection Agreement to the extent necessary.

Transmission Provider shall mean the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Variable Energy Resource shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Article 2. Effective Date, Term, and Termination

2.1 Effective Date. This LGIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this LGIA with FERC upon execution in accordance with Article 3.1, if required.

2.2 Term of Agreement. Subject to the provisions of Article 2.3, this LGIA shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as Interconnection Customer may request (Term to be specified in individual agreements) and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures.

2.3.1 Written Notice. This LGIA may be terminated by Interconnection Customer after giving Transmission Provider ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

2.3.2 Default. Either Party may terminate this LGIA in accordance with Article 17.

2.3.3 Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this LGIA, which notice has been accepted for filing by FERC.

2.4 Termination Costs. If a Party elects to terminate this Agreement pursuant to Article 2.3 above, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party, as of the date of the other Party's receipt of such notice of

termination, that are the responsibility of the Terminating Party under this LGIA. In the event of termination by a Party, the Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this LGIA, unless otherwise ordered or approved by FERC:

2.4.1 With respect to any portion of Transmission Provider's Interconnection Facilities that have not yet been constructed or installed, Transmission Provider shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Provider shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Provider for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Provider shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Provider to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this LGIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities

and equipment, and other expenses including any Network Upgrades for which Transmission Provider has incurred expenses and has not been reimbursed by Interconnection Customer.

2.4.2 Transmission Provider may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Provider shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this LGIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 **Disconnection.** Upon termination of this LGIA, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 **Survival.** This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this LGIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

Article 3. Regulatory Filings

3.1 Filing. Transmission Provider shall file this LGIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this LGIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

Article 4. Scope of Service

4.1 Interconnection Product Options. Interconnection Customer has selected the following (checked) type of Interconnection Service:

X **4.1.1 Energy Resource Interconnection Service.**

4.1.1.1 The Product. Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interconnection Service, Transmission Provider shall construct facilities identified in Attachment A.

4.1.1.2 Transmission Delivery Service Implications. Under Energy

Resource Interconnection Service, Interconnection Customer will be eligible to inject power from the Large Generating Facility into and deliver power across the interconnecting Transmission Provider's Transmission System on an "as available" basis up to the amount of MWs identified in the applicable stability and steady state studies to the extent the upgrades initially required to qualify for Energy Resource Interconnection Service have been constructed. Where eligible to do so (e.g., PJM, ISO-NE, NYISO), Interconnection Customer may place a bid to sell into the market up to the maximum identified Large Generating Facility output, subject to any conditions specified in the interconnection service approval, and the Large Generating Facility will be dispatched to the extent Interconnection Customer's bid clears. In all other instances, no transmission delivery service from the Large Generating Facility is assured, but Interconnection Customer may obtain Point-to-Point Transmission Service, Network Integration Transmission Service, or be used for secondary network transmission service, pursuant to Transmission Provider's Tariff, up to the maximum output identified in the stability and steady state studies. In those instances, in order for Interconnection Customer to obtain the right to deliver or inject energy beyond the Large Generating Facility Point of Interconnection or to improve its ability to do so, transmission

delivery service must be obtained pursuant to the provisions of Transmission Provider's Tariff. The Interconnection Customer's ability to inject its Large Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of Transmission Provider's Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of firm Point-to-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

☐ **4.1.2 Network Resource Interconnection Service.**

4.1.2.1 The Product. Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as all Network Resources. To the extent Interconnection Customer wants to receive Network Resource Interconnection Service, Transmission Provider shall construct the facilities identified in Attachment A to this LGIA.

4.1.2.2 Transmission Delivery Service Implications. Network Resource

Interconnection Service allows Interconnection Customer's Large Generating Facility to be designated by any Network Customer under the Tariff on Transmission Provider's Transmission System as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Large Generating Facility in the same manner as it accesses Network Resources. A Large Generating Facility receiving Network Resource Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Large Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Large Generating Facility has not been designated as a Network Resource by any load, it cannot be

required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or firm Point-to-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Large Generating Facility to any particular load on Transmission Provider's Transmission System without incurring congestion costs. In the event of transmission constraints on Transmission Provider's Transmission System, Interconnection Customer's Large Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that Interconnection Customer's Large Generating Facility be designated

as a Network Resource by a Network Service Customer under the Tariff or that Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does designate the Large Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interconnection Service, any future transmission service request for delivery from the Large Generating Facility within Transmission Provider's Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Large Generating Facility be undertaken, regardless of whether or not such Large Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Large Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Large Generating Facility outside

Transmission Provider's Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

4.2 **Provision of Service.** Transmission Provider shall provide Interconnection Service for the Large Generating Facility at the Point of Interconnection.

4.3 **Performance Standards.** Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is a Transmission Provider or Transmission Owner, then that Party shall amend the LGIA and submit the amendment to FERC for approval.

4.4 **No Transmission Delivery Service.** The execution of this LGIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

4.5 **Interconnection Customer Provided Services.** The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.5.1.

Interconnection Customer shall be paid for such services in accordance with Article 11.6.

Article 5. Interconnection Facilities Engineering, Procurement, and Construction

5.1 **Options.** Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either Standard Option or Alternate Option set forth below for

completion of Transmission Provider's Interconnection Facilities and Network Upgrades as set forth in Appendix A, Interconnection Facilities and Network Upgrades, and such dates and selected option shall be set forth in Appendix B, Milestones.

5.1.1 **Standard Option.** Transmission Provider shall design, procure, and construct Transmission Provider's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Provider shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Provider reasonably expects that it will not be able to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the specified dates, Transmission Provider shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 **Alternate Option.** If the dates designated by Interconnection Customer are acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities by the designated dates.

If Transmission Provider subsequently fails to complete Transmission Provider's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to

complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B, Milestones; Transmission Provider shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable RTO or ISO refuses to grant clearances to install equipment.

5.1.3 **Option to Build.** If the dates designated by Interconnection Customer are not acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. Transmission Provider and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 **Negotiated Option.** If Interconnection Customer elects not to exercise its option under Article 5.1.3, Option to Build, Interconnection Customer shall so notify Transmission Provider within thirty (30) Calendar Days, and the Parties shall in

good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades by Interconnection Customer) pursuant to which Transmission Provider is responsible for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, Transmission Provider shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Network Upgrades pursuant to 5.1.1, Standard Option.

5.2 General Conditions Applicable to Option to Build. If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Provider;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Provider shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider;

(5) at any time during construction, Transmission Provider shall have the right to gain unrestricted access to Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Provider, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider for claims arising from Interconnection Customer's construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) Interconnection Customer shall transfer control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Provider's Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Provider;

(10) Transmission Provider shall approve and accept for operation and maintenance Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information, and any other documents that are reasonably required by Transmission Provider to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

5.3 Liquidated Damages. The actual damages to Interconnection Customer, in the event Transmission Provider's Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Provider pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Provider to Interconnection Customer in the event that Transmission Provider does not complete any portion of Transmission Provider's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of Transmission Provider's Interconnection Facilities and Network

Upgrades, in the aggregate, for which Transmission Provider has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades for which Transmission Provider has assumed responsibility to design, procure, and construct. The foregoing payments will be made by Transmission Provider to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Transmission Provider's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for the Large Generating Facility's Trial Operation or to export power from the Large Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for Large Generating Facility's Trial Operation or to export power from the Large Generating Facility, but for Transmission Provider's delay; (2) Transmission Provider's failure to meet the specified dates is the result of the action or inaction of Interconnection Customer or any other Interconnection Customer who has entered into an LGIA with Transmission Provider or any cause beyond Transmission Provider's reasonable control or reasonable ability to cure; (3) the interconnection Customer has assumed responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 Power System Stabilizers. The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative. The requirements of this paragraph shall not apply to wind generators.

5.5 Equipment Procurement. If responsibility for construction of Transmission Provider's Interconnection Facilities or Network Upgrades is to be borne by Transmission Provider, then Transmission Provider shall commence design of Transmission Provider's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 Transmission Provider has completed the Facilities Study pursuant to the Facilities Study Agreement;

5.5.2 Transmission Provider has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.5.3 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.6 Construction Commencement. Transmission Provider shall commence construction of Transmission Provider's Interconnection Facilities and Network Upgrades for which it is responsible as soon as

practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Provider's Interconnection Facilities and Network Upgrades;

5.6.3 Transmission Provider has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.6.4 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.7 **Work Progress.** The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Either Party may, at any time, request a progress report from the other Party. If, at any time, Interconnection Customer determines that the completion of Transmission Provider's Interconnection Facilities will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider of such later date upon which the completion of Transmission Provider's Interconnection Facilities will be required.

5.8 **Information Exchange.** As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with Transmission Provider's Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 Limited Operation. If any of Transmission Provider's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Large Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Large Generating Facility and Interconnection Customer's Interconnection Facilities may operate prior to the completion of Transmission Provider's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. Transmission Provider shall permit Interconnection Customer to operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.10 Interconnection Customer's Interconnection Facilities ('ICIF'). Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.10.1 Interconnection Customer's Interconnection Facility Specifications. Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Provider at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Provider shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's

submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 **Transmission Provider's Review.** Transmission Provider's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Provider, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider.

5.10.3 **ICIF Construction.** The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Large Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Large Generating Facility. The Interconnection Customer shall provide Transmission Provider specifications for the excitation system, automatic voltage regulator, Large

Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.11 Transmission Provider's Interconnection Facilities Construction. Transmission Provider's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Provider shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Provider's Interconnection Facilities [include appropriate drawings and relay diagrams].

Transmission Provider will obtain control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

5.12 Access Rights. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to the other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the Transmission System; (ii) operate and maintain the Large Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed

from time to time, by the Granting Party and provided to the Access Party.

5.13 **Lands of Other Property Owners**. If any part of Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Provider or Transmission Owner, Transmission Provider or Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

5.14 **Permits.** Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

5.15 **Early Construction of Base Case Facilities.** Interconnection Customer may request Transmission Provider to construct, and Transmission Provider shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not

scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 Suspension. Interconnection Customer reserves the right, upon written notice to Transmission Provider, to suspend
at any time all work by Transmission Provider associated with the construction and installation of Transmission Provider's Interconnection Facilities and/or Network Upgrades required under this LGIA with the condition that Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Provider's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Provider (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Provider cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Provider shall obtain Interconnection Customer's authorization to do so.

Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Transmission Provider required under this LGIA pursuant to this Article 5.16, and has not requested Transmission Provider to recommence the work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Transmission Provider, if no effective date is specified.

5.17 Taxes.

5.17.1 **Interconnection Customer Payments Not Taxable.** The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Provider for the installation of Transmission Provider's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 **Representations and Covenants.** In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to Transmission Provider for Transmission Provider's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of Transmission Provider's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to

IRS requirements for non-taxable treatment.

At Transmission Provider's request, Interconnection Customer shall provide Transmission Provider with a report from an independent engineer confirming its representation in clause (iii), above. Transmission Provider represents and covenants that the cost of Transmission Provider's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 **Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon the Transmission Provider.** Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Transmission Provider from the cost consequences of any current tax liability imposed against Transmission Provider as the result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Transmission Provider.

Transmission Provider shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this LGIA unless (i) Transmission Provider has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Transmission Provider should be reported as income subject to taxation or (ii) any Governmental Authority directs Transmission Provider to report payments or property as income subject to taxation; provided, however, that Transmission Provider may require Interconnection Customer to provide security for

Interconnection Facilities, in a form reasonably acceptable to Transmission Provider (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Transmission Provider for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Transmission Provider of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by Transmission Provider upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 **Tax Gross-Up Amount.** Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Interconnection Customer will pay Transmission Provider, in addition to the amount paid for the Interconnection Facilities and Network Upgrades, an amount equal to (1) the current taxes imposed on Transmission Provider ("Current Taxes") on the excess of (a) the gross income realized by Transmission Provider as a result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount")

over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit Transmission Provider to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Transmission Provider's composite federal and state tax rates at the time the payments or property transfers are received and Transmission Provider will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Transmission Provider's anticipated tax depreciation deductions as a result of such payments or property transfers by Transmission Provider's current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.17.5 **Private Letter Ruling or Change or Clarification of Law.** At Interconnection Customer's request and expense, Transmission Provider shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Transmission

Provider under this LGIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Transmission Provider and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Transmission Provider shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Transmission Provider shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 **Subsequent Taxable Events.** If, within 10 years from the date on which the relevant Transmission Provider's Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this LGIA terminates and Transmission Provider retains ownership of the Interconnection Facilities and Network Upgrades, Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Transmission Provider, calculated using the methodology described

in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 **Contests.** In the event any Governmental Authority determines that Transmission Provider's receipt of payments or property constitutes income that is subject to taxation, Transmission Provider shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Transmission Provider may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Transmission Provider reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Transmission Provider shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Transmission Provider may agree to a settlement either with Interconnection

Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Transmission Provider, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Transmission Provider for the tax at issue in the contest.

5.17.8 **Refund.** In the event that (a) a private letter ruling is issued to Transmission Provider which holds that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Transmission Provider in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not taxable to Transmission Provider, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Transmission Provider are not subject to federal income

tax, or (d) if Transmission Provider receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Transmission Provider pursuant to this LGIA, Transmission Provider shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by Interconnection Customer to Transmission Provider for such taxes which Transmission Provider did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Transmission Provider refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Transmission Provider, any refund or credit Transmission Provider receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to Transmission Provider for such overpayment of taxes (including any reduction in interest otherwise payable by Transmission Provider to any Governmental Authority resulting

from an offset or credit); _provided, however_, that Transmission Provider will remit such amount promptly to Interconnection Customer only after and to the extent that Transmission Provider has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to Transmission Provider's Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 **Taxes Other Than Income Taxes.** Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Provider for which Interconnection Customer may be required to reimburse Transmission Provider under the terms of this LGIA. Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Transmission Provider shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Transmission Provider for such

taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Provider.

5.17.10 Transmission Owners Who Are Not Transmission Providers. If Transmission Provider is not the same entity as the Transmission Owner, then (i) all references in this Article 5.17 to Transmission Provider shall be deemed also to refer to and to include the Transmission Owner, as appropriate, and (ii) this LGIA shall not become effective until such Transmission Owner shall have agreed in writing to assume all of the duties and obligations of Transmission Provider under this Article 5.17 of this LGIA.

5.18 Tax Status. Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this LGIA is intended to adversely affect any Transmission Provider's tax exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General. Either Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, that Party shall provide to the other Party sufficient information regarding such modification so that the other Party may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall

include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Large Generating Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Provider shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Provider's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 **Standards.** Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 **Modification Costs.** Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Provider makes to Transmission Provider's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Provider's Interconnection Facilities or the Transmission System, or to provide

transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

Article 6. Testing and Inspection

6.1 Pre-Commercial Operation Date Testing and Modifications. Prior to the Commercial Operation Date, Transmission Provider shall test Transmission Provider's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Large Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Large Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications. Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Large Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 **Right to Observe Testing.** Each Party shall notify the other Party in advance of its performance of tests of its Interconnection Facilities. The other Party has the right, at its own expense, to observe such testing.

6.4 **Right to Inspect.** Each Party shall have the right, but shall have no obligation to: (i) observe the other Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of the other Party's System Protection Facilities and other protective equipment; and (iii) review the other Party's maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. A Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Party. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this LGIA.

Article 7. Metering

7.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Provider shall install Metering Equipment at the Point of Interconnection prior to any operation of the Large Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Large Generating Facility shall be measured at or, at Transmission Provider's option, compensated to, the Point of Interconnection. Transmission Provider shall provide metering quantities, in analog and/or digital form, to Interconnection Customer upon request. Interconnection Customer shall bear all

reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 Check Meters. Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Provider's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Provider or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 Standards. Transmission Provider shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

7.4 Testing of Metering Equipment. Transmission Provider shall inspect and test all Transmission Provider-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Transmission Provider shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than every two (2) years. Transmission Provider shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Provider's failure to maintain, then Transmission Provider shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission

Provider shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

7.5 Metering Data. At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Provider and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Large Generating Facility to the Point of Interconnection.

Article 8. Communications

8.1 Interconnection Customer Obligations. Interconnection Customer shall maintain satisfactory operating communications with Transmission Provider's Transmission System dispatcher or representative designated by Transmission Provider. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Large Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Provider as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Large Generating Facility to the location(s) specified by Transmission Provider. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation,

scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 **Remote Terminal Unit.** Prior to the Initial Synchronization Date of the Large Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Provider at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Provider through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Provider. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Provider.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 **No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4 **Provision of Data from a Variable Energy Resource.** The Interconnection Customer whose Generating Facility is a Variable Energy Resource shall provide meteorological and forced outage data to the Transmission Provider to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The Interconnection Customer with a Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, wind

speed, wind direction, and atmospheric pressure. The Interconnection Customer with a Variable Energy Resource having solar as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission Provider and Interconnection Customer whose Generating Facility is a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility is a Variable Energy Resource also shall submit data to the Transmission Provider regarding all forced outages to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Such requirements for meteorological and forced outage data are set forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

Article 9. Operations

9.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 **Control Area Notification**. At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider in

writing of the Control Area in which the Large Generating Facility will be located. If Interconnection Customer elects to locate the Large Generating Facility in a Control Area other than the Control Area in which the Large Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Control Area.

9.3 Transmission Provider Obligations. Transmission Provider shall cause the Transmission System and Transmission Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA. Transmission Provider may provide operating instructions to Interconnection Customer consistent with this LGIA and Transmission Provider's operating protocols and procedures as they may change from time to time. Transmission Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations. Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA. Interconnection Customer shall operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this LGIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Either Party may request that the other Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this LGIA.

9.5 Start-Up and Synchronization. Consistent with the Parties' mutually acceptable procedures, Interconnection Customer is responsible for the proper synchronization of the Large Generating Facility to Transmission Provider's Transmission System.

9.6 Reactive Power and Primary Frequency Response.

9.6.1 Power Factor Design Criteria. Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis. The requirements of this paragraph shall not apply to wind generators.

9.6.1.1 Synchronous Generation. Interconnection Customer shall design the Large Generating Facility to maintain a composite power deliver at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all synchronous generators in the Control Area on a comparable basis.

9.6.1.2 Non-Synchronous Generation. Interconnection Customer shall design the Large Generating Facility to maintain composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all non-synchronous generators in the Control Area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of the Final Rule establishing this requirement (Order No. 827).

9.6.2 **Voltage Schedules.** Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Transmission Provider shall require Interconnection Customer to operate the Large Generating Facility to produce or absorb reactive power within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Provider's voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. Transmission Provider shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance,

and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Large Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the System Operator.

9.6.2.1 Voltage Regulators. Whenever the Large Generating Facility is operated in parallel with the Transmission System and voltage regulators are capable of operation, Interconnection Customer shall operate the Large Generating Facility with its voltage regulators in automatic operation. If the Large Generating Facility's voltage regulators are not capable of such automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative, and ensure that such Large Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Large Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Large Generating

Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Control Area on a comparable basis.

9.6.3 **Payment for Reactive Power.** Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Large Generating Facility when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1, provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed.

9.6.4 Primary Frequency Response. Interconnection Customer shall ensure the primary frequency response capability of its Large Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term “functioning governor or equivalent controls” as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Large Generating Facility’s real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Large Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Large Generating Facility’s real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Large Generating Facility’s real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Large Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Interconnection Customer shall operate the Large Generating Facility consistent with the provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Large Generating Facilities.

9.6.4.1 Governor or Equivalent Controls. Whenever the Large Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Large Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Large Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Large Generating Facility’s governor or equivalent controls to a minimum whenever the Large Generating Facility is operated in parallel with the Transmission System.

9.6.4.2 Timely and Sustained Response. Interconnection Customer shall ensure that the Large Generating Facility’s real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Large Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Large Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

9.6.4.3 **Exemptions.** Large Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement. Large Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 9.6.4, but shall be otherwise exempt from the operating requirements in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.4 of this Agreement.

9.6.4.4 **Electric Storage Resources.** Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Appendix C of its LGIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.3 of this Agreement. Appendix C shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Appendix C must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer’s electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 9.6.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer’s electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer’s electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination. Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to the Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Party of such removal.

9.7.1.2 **Outage Schedules.** Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Large Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

9.7.1.3 Outage Restoration. If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects the other Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Party, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

9.7.2 Interruption of Service. If required by Good Utility Practice to do so, Transmission Provider may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Provider;

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Large Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 **Under-Frequency and Over Frequency Conditions.** The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability of the Transmission System. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

9.7.4 **System Protection and Other Control Requirements.**

9.7.4.1 **System Protection Facilities.** Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or

Interconnection Customer's Interconnection Facilities. Transmission Provider shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Provider's Interconnection Facilities or the Transmission System as a result of the interconnection of the Large Generating Facility and Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

9.7.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 Requirements for Protection. In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Provider's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Large Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Large Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Large Generating Facility.

9.7.6 Power Quality. Neither Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

9.8 Switching and Tagging Rules. Each Party shall provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Provider's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.10 **Disturbance Analysis Data Exchange.** The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or Transmission Provider's Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

Article 10. Maintenance

10.1 **Transmission Provider Obligations.** Transmission Provider shall maintain the Transmission System and Transmission Provider's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.2 **Interconnection Customer Obligations.** Interconnection Customer shall maintain the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.3 **Coordination.** The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Large Generating Facility and the Interconnection Facilities.

10.4 Secondary Systems. Each Party shall cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Party. Each Party shall provide advance notice to the other Party before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

10.5 Operating and Maintenance Expenses. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Provider's Interconnection Facilities.

Article 11. Performance Obligation

11.1 Interconnection Customer Interconnection Facilities. Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

11.2 Transmission Provider's Interconnection Facilities. Transmission Provider or Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Provider's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

11.3 Network Upgrades and Distribution Upgrades. Transmission Provider or Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades. The Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless Transmission Provider or Transmission Owner elects to fund the capital for the Network Upgrades, they shall be solely funded by Interconnection Customer. In the event that Transmission Provider must change the voltage levels of a discrete portion of the Transmission System to which the Interconnection Customer is connected, Transmission Provider shall give reasonable notice of such change and the Interconnection Customer shall be solely responsible for all costs related to upgrades or modifications to Interconnection Customer’s Interconnection Facilities resulting from Transmission Provider’s increase in the voltage levels of the Transmission System, in order to remain interconnected with the Transmission System at the new operating voltage. To the extent that the modifications necessary to upgrade Interconnection Facilities qualify as Network Upgrades, Transmission Provider shall be solely responsible for the expense of such modifications or upgrades.

11.4 Transmission Credits.

11.4.1 Repayment of Amounts Advanced for Network Upgrades. Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to Transmission Provider and Affected System Operator, if any, for the Network Upgrades, including any tax gross-up or other tax-related payments associated with Network Upgrades, and not refunded to Interconnection

Customer pursuant to Article 5.17.8 or otherwise, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Large Generating Facility. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC=s regulations at 18 C.F.R. § 35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. Interconnection Customer may assign such repayment rights to any person.

Notwithstanding the foregoing, Interconnection Customer, Transmission Provider, and Affected System Operator may adopt any alternative payment schedule that is mutually agreeable so long as Transmission Provider and Affected System Operator take one of the following actions no later than five years from the Commercial Operation Date: (1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or (2) declare in writing that Transmission Provider or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full reimbursement shall not extend beyond twenty (20) years from the Commercial Operation Date.

If the Large Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, Transmission Provider and Affected System Operator shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the Generating Facility, if different, is responsible for identifying the entity to which reimbursement must be made.

11.4.2 **Special Provisions for Affected Systems.** Unless Transmission Provider provides, under the LGIA, for the repayment of amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

11.4.3 Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Large Generating Facility.

11.5 Provision of Security. At least thirty (30) Calendar Days prior to the commencement of the first of the following to occur: design, procurement, installation, or construction of a discrete portion of a Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to Transmission Provider for these purposes.

In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must indicate that it would only expire upon final payment made to Transmission Provider to cover all relevant costs for designing, procuring, installing, and constructing the applicable portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which the letter of credit was provided.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must indicate that it would only expire upon final payment made to Transmission Provider to cover all relevant costs for designing, procuring, installing, and constructing the applicable portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which the surety bond was provided.

11.6 Interconnection Customer Compensation. If Transmission Provider requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this LGIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to an RTO or ISO FERC-approved rate schedule. Interconnection Customer shall serve Transmission Provider or RTO or ISO with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this LGIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

11.6.1 Interconnection Customer Compensation for Actions During Emergency Condition. Transmission Provider or RTO or ISO shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.6.

Article 12. Invoice

12.1 General. Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this LGIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice. Within six months after completion of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades, Transmission Provider shall provide an invoice of the final cost of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades and shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this LGIA.

12.4 Disputes. In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide Interconnection Service under this LGIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii).

Article 13. Emergencies

13.1 Definition. "Emergency Condition" shall mean a condition or situation: (i) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (ii) that, in the case of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, Transmission Provider's Interconnection Facilities or the Transmission Systems of others to which the Transmission System is directly connected; or (iii) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Large Generating Facility or Interconnection Customer's Interconnection Facilities' System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by this LGIA to possess black start capability.

13.2 Obligations. Each Party shall comply with the Emergency Condition procedures of the applicable ISO/RTO, NERC, the Applicable Reliability Council, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

13.3 Notice. Transmission Provider shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Provider's Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Transmission Provider promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Provider's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Provider's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

13.4 Immediate Action. Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Provider, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or otherwise regarding the Transmission System.

13.5 Transmission Provider Authority.

13.5.1 General. Transmission Provider may take whatever actions or inactions with regard to the Transmission System or Transmission Provider's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Provider's Interconnection

Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Large Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 **Reduction and Disconnection.** Transmission Provider may reduce Interconnection Service or disconnect the Large Generating Facility or Interconnection Customer's Interconnection Facilities, when such, reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of Transmission Provider pursuant to Transmission Provider's Tariff. When

Transmission Provider can schedule the reduction or disconnection in advance, Transmission Provider shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection Customer and Transmission Provider. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities, and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

13.6 Interconnection Customer Authority. Consistent with Good Utility Practice and the LGIA and the LGIP, Interconnection Customer may take actions or inactions with regard to the Large Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Provider's Interconnection Facilities. Transmission Provider shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.7 Limited Liability. Except as otherwise provided in Article 11.6.1 of this LGIA, neither Party shall be liable to the other for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

Article 14. Regulatory Requirements and Governing Law

14.1 Regulatory Requirements. Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this LGIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act, the Public Utility Holding Company Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

Article 15. Notices.

15.1 General. Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Either Party may change the notice information in this LGIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Party in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

Article 16. Force Majeure

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

Article 17. Default

17.1 Default

17.1.1 **General.** No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act of omission of the other Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 Right to Terminate. If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this LGIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this LGIA.

Article 18. Indemnity, Consequential Damages and Insurance

18.1 Indemnity. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this LGIA on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnified Party.

18.1.1 Indemnified Person. If an Indemnified Person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such Indemnified Person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 **Indemnifying Party**. If an Indemnifying Party is obligated to indemnify and hold any Indemnified Person harmless under this Article 18, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

18.1.3 **Indemnity Procedures**. Promptly after receipt by an Indemnified Person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Person shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the Indemnifying Party and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the Indemnifying Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses.

The Indemnified Person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the Indemnified Person and the Indemnifying Party, in such event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be reasonably withheld, conditioned or delayed.

18.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 Insurance. Each party shall, at its own expense, maintain in force throughout the period of this LGIA, and until released by the other Party, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this LGIA.

18.3.9 Within ten (10) days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, each Party shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

Article 19. Assignment

19.1 Assignment. This LGIA may be assigned by either Party only with the written consent of the other; provided that either Party may assign this LGIA without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this LGIA; and provided further that Interconnection Customer shall have the right to assign this LGIA, without the consent of Transmission Provider, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that Interconnection Customer will promptly notify Transmission Provider of any such assignment. Any financing arrangement entered into by Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured Party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider of the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

Article 20. Severability

20.1 Severability. If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental

Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Provider) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

Article 21. Comparability

21.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

Article 22. Confidentiality

22.1 Confidentiality. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 **Term.** During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 **Scope.** Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of the LGIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

22.1.3 **Release of Confidential Information.** Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 **Rights**. Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 **No Warranties**. By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 **Standard of Care**. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this LGIA or its regulatory requirements.

22.1.7 **Order of Disclosure.** If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this LGIA.

Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 **Termination of Agreement.** Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

22.1.9 **Remedies.** The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 **Disclosure to FERC, its Staff, or a State.** Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 CFR section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this LGIA prior to the release of the Confidential Information to FERC or its staff. The

Party shall notify the other Party to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this LGIA ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

Article 23. Environmental Releases

23.1 Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

Article 24. Information Requirements

24.1 **Information Acquisition**. Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 **Information Submission by Transmission Provider**. The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 Updated Information Submission by Interconnection Customer. The updated information submission by Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Trial Operation. Interconnection Customer shall submit a completed copy of the Large Generating Facility data requirements contained in Appendix 1 to the LGIP. It shall also include any additional information provided to Transmission Provider for the Feasibility and Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study Agreement between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on Transmission Provider Transmission System based on the actual data submitted pursuant to this Article 24.3. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

24.4 Information Supplementation. Prior to the Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Large Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Large Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Large Generating Facility to verify proper operation of the Large Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Large Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent change in Large Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Large Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Large Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Large Generating Facility terminal or field voltages is provided. Large Generating Facility testing shall be conducted and results provided to Transmission Provider for each individual generating unit in a station.

Subsequent to the Operation Date, Interconnection Customer shall provide Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Provider shall provide Interconnection Customer any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Provider-owned substation that may affect Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

Article 25. Information Access and Audit Rights

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Party information that is in the possession of the disclosing Party and is necessary in order for the other Party to: (i) verify the costs incurred by the disclosing Party for which the other Party is responsible under this LGIA; and (ii) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA.

25.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Party when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this LGIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this LGIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party, to audit at its own expense the other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this LGIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this LGIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods.

25.4.1 **Audit Rights Period for Construction-Related Accounts and Records.** Accounts and records related to the design, engineering, procurement, and construction of Transmission Provider's Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission Provider's issuance of a final invoice in accordance with Article 12.2.

25.4.2 **Audit Rights Period for All Other Accounts and Records.** Accounts and records related to either Party's performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

25.5 Audit Results. If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

Article 26. Subcontractors

26.1 General. Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

26.2 Responsibility of Principal. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Provider be liable for the actions or inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

Article 27. Disputes

27.1 Submission. In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 External Arbitration Procedures. Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail.

27.3 Arbitration Decisions. Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

27.4 Costs. Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

Article 28. Representations, Warranties, and Covenants

28.1 General. Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 Authority. Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 **No Conflict**. The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 **Consent and Approval**. Such Party has sought or obtained, or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

Article 29. Joint Operating Committee

29.1 Joint Operating Committee. Except in the case of ISOs and RTOs, Transmission Provider shall constitute a Joint Operating Committee to coordinate operating and technical considerations of Interconnection Service. At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Interconnection Customer shall notify Transmission Provider of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of either Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this LGIA. Each Party shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

29.1.1 Establish data requirements and operating record requirements.

29.1.2 Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

29.1.3 Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Provider's and Interconnection Customer's facilities at the Point of Interconnection.

29.1.4 Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Large Generating Facility and other facilities that impact the normal operation of the interconnection of the Large Generating Facility to the Transmission System.

29.1.5 Ensure that information is being provided by each Party regarding equipment availability.

29.1.6 Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

Article 30. Miscellaneous

30.1 Binding Effect. This LGIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts. In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation. This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix to this LGIA, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 Entire Agreement. This LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this LGIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this LGIA.

30.5 No Third Party Beneficiaries. This LGIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 Waiver. The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party. Any waiver at any time by either Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this LGIA. Termination or Default of this LGIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 Headings. The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

30.8 Multiple Counterparts. This LGIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment. The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by the Parties.

30.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. Transmission Provider shall have the right to make a unilateral filing with FERC to modify this LGIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

IN WITNESS WHEREOF, the Parties have executed this LGIA in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

PACIFICORP, on behalf of its Transmission function

By: ______________________
Rick Vail
Title: VP, Transmission

Date: 2/19/2019

PACIFICORP, on behalf of its Marketing function (Q708)

By: ______________________

Title: SVP, Bus. Policy & Development

Date: Feb. 15, 2019

Appendix A to LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

1. **Interconnection Facilities:**

   (a) **Interconnection Customer's Interconnection Facilities:** Two (2) circuit breakers, one each on the high side of the Interconnection Customer's step up transformers, connected to an approximately 12 mile 230 kV transmission line. The transmission line is then connected to a circuit breaker to be installed in the collector substation constructed for the Interconnection Request assigned queue position Q0707. From that point the Interconnection Customer will share the Interconnection Facilities installed for Q0707including a short generator tie line to the Point of Interconnection (Shirley Basin) substation. Please see Exhibit 1 to Attachment A.

   (b) **Transmission Provider's Interconnection Facilities:** Five (5) production meters located at the high side of the step up transformers at the Interconnection Customer collector substations as well as relaying and communications equipment, low side metering, one (1) interchange meter at the Point of Change of Ownership, and one line position (dead end structure, disconnect switch, metering structure) located at the Point of Interconnection (Shirley Basin) substation. Please see Exhibit 1 to Attachment A.

2. **Network Upgrades:**

   (a) **Stand Alone Network Upgrades:** None

   (b) **Other Network Upgrades:** RAS relaying upgrades at Shirley Basin and other substations.

3. **Distribution Upgrades:** None

4. **Contingent Facilities:** As identified in the System Impact Study for this project dated August 21, 2018 the following Network Upgrades are required to be in-service prior to this project:

- Segment D2 (500 kV line Aeolus-Anticline/Bridger). (Transmission Provider internal, 2020)
- A Remedial Action Scheme ("RAS") that will drop up to 600 MW of generation for various 500 kV outages. (Transmission Provider internal, 2020)
- All Interconnection Facilities and associated Network Upgrades required for the Interconnection Request assigned queue position Q0707 including a new 230 kV transmission line between Shirley Basin and Aeolus substations. (2020)

If the schedule for completion of these upgrades changes the Transmission Provider reserves the right to restudy this project to determine any additional requirements to assign to this project necessary to facilitate interconnection of this project by the date required.

5. Point of Interconnection ("POI"): The point at which Transmission Provider Interconnection Facilities connect to the substation bus at the Shirley Basin substation (see Exhibit 1 to Appendix A).

6. Point of Change of Ownership: The point at which Interconnection Customer and Transmission Provider Interconnection Facilities meet (see Exhibit 1 to Appendix A)

7. One-Line Diagram: is attached to this agreement as Exhibit 1 to Appendix A.

8. **Estimated Project Cost:** $1,440,000
Direct Assigned: $1,440,000
Network Upgrade: $0

Appendix B To LGIA

Milestones

Milestone	Party
Execute Interconnection Agreement January 23, 2019	Interconnection Customer
Provision of Financial Security ($250,000) January 23, 2019	Interconnection Customer
Design Information Provided January 23, 2019	Interconnection Customer
Property/Permits/ROW Procured February 1, 2019	Interconnection Customer
Provide construction approval April 1, 2019	Interconnection Customer
**Energy Imbalance Market Modeling Data Submittal April 10, 2019	Interconnection Customer
Engineering Design Complete April 10, 2019	Transmission Provider
Construction Begins May 1, 2019	Transmission Provider
Facilities Receive Backfeed Power June 15, 2020	Interconnection Customer
***Contingent facilities complete October 1, 2020	Transmission Provider
Initial Synchronization and Generation Testing October 1, 2020	Interconnection Customer
Commercial Operation November 1, 2020	Interconnection Customer

*As applicable and determined by the Transmission Provider, within 60 days of the Interconnection Customer’s authorization for the Transmission Provider to begin engineering, the Interconnection Customer shall provide a detailed short circuit model of its generation system. This model must be constructed using the ASPEN One-Line short circuit simulation program and contain all individual electrical components of the Interconnection Customer's generation system.

**Any design modifications to the Interconnection Customer's Generating Facility after this date requiring updates to the Transmission Provider's network model will result in a minimum of 3 months added to all future milestones including Commercial Operation.

***Delays in completion of Contingent Facilities will impact the in-service date of the project.

Term of Agreement: In accordance with LGIA Article 2.2, the Parties agree that the term of the LGIA shall be ten (10) years from the Effective Date and shall be automatically renewed for each successive one-year period thereafter.

Construction Option: The Network Upgrades, Direct Assignment Facilities and Transmission Provider Interconnection Facilities will be designed, procured and constructed by the Transmission Provider in accordance with the Standard Option outlined in Article 5.1.1 of this Agreement. The Network Upgrades, Direct Assignment Facilities and Transmission Provider Interconnection Facilities shall be constructed in accordance with the Scope of Work attached to this LGIA as Exhibit 1 to Appendix B. The Network Upgrades, Direct Assignment Facilities and Transmission Provider's Interconnection Facilities shall be designed, procured and constructed in a timely manner to support the Milestone Dates stated above.

Appendix C To LGIA

Interconnection Details

Description of the Large Generating Facility: The Interconnection Customer's Large Generating Facility consists of fourteen (14) Vestas V110 2.0 and fifty-three (53) Vestas V136 4.3 turbines connected to twelve (12) 34.5 kV strings for a total generation output of 250 MW as measured at the POI. The Large Generating facility is separated in two parts, three (3) strings of turbines are connected to the collector substation constructed for the Interconnection Request assigned queue position Q0707 and nine (9) strings of turbines are located approximately 11.6 miles away (with corresponding tie line to the Q0707 collector substation). The strings are then connected to five (in parallel) 75/100/125 MVA 34.5 – 230 kV (7.5% impedance) transformers. The Large Generating Facility is located in Carbon County, Wyoming.

Please see Exhibit 1 to Attachment A.

Control Area Requirements: Interconnection Customer shall interconnect and operate the Large Generating Facility in accordance with the Transmission Provider's Facility Interconnection Requirements for Transmission Systems, as may be revised from time to time, attached hereto as Exhibit 1 to Appendix C and by this reference incorporated herein.

Interconnection Details:
Metering. With reference to Article 7.1, Transmission Provider will own and maintain the bi-directional revenue Metering Equipment in Transmission Provider's Point of Interconnection substation at the Interconnection Customer's expense.

Under Frequency and Over Frequency Conditions. Consistent with LGIA Article 9.7.3, Transmission Provider shall design, procure, install and maintain frequency and voltage protection to trip feeder breakers in accordance with the settings shown in Exhibit 1 to Appendix C.

Reactive Power and Voltage Schedule. All interconnecting synchronous and non-synchronous generators are required to design their Generating Facilities with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices. For non-synchronous generators, the power factor requirement is to be measured at the high-side of the generator substation. The Generating Facility must provide dynamic reactive power to the system over the full range of real power output. If the Generating Facility is not capable of providing positive reactive support (i.e., supplying reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations, the facility will be required to add dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.

Generators shall be equipped with automatic voltage-control equipment and normally operated with the voltage regulation control mode enabled unless written authorization, or directive, from the Transmission Provider is given to operate in another control mode (e.g., constant power factor control). The control mode of generating units shall be accurately represented in operating studies. The generators shall be capable of operating continuously at their rated power output within +/- 5% of its rated terminal voltage. Phasor Measurement Units will be required at any Generating Facilities with an individual or aggregate nameplate capacity of 75 MVA or greater.

As required by NERC standard VAR-001-1a, the Transmission Provider will provide a voltage schedule for the Point of Interconnection. In general, Generating Facilities should be operated so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Transmission Provider, in accordance with Transmission Provider Policy 139.

Generating Facilities capable of operating with a voltage droop are required to do so. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer’s responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing. If the need for a master controller is identified, the cost and all related installation requirements will be the responsibility of the

Interconnection Customer. Participation by the Generation Facility in subsequent interaction/coordination studies will be required pre- and post-commercial operation in order ensure system reliability.

All generators must meet the Federal Energy Regulatory Commission (FERC) and WECC low voltage ride-through requirements.

As the Transmission Provider cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

Property Requirements. Subject to LGIA Articles 5.12 and 5.13, Interconnection Customer is required to obtain for the benefit of Transmission Provider at Interconnection Customer’s sole cost and expense all real property rights, including but not limited to fee ownership, easements and/or rights of way, as applicable, for Transmission Provider owned facilities using forms acceptable to Transmission Provider. Transmission Provider shall not be obligated to accept any such real property right that does not, at Transmission Provider’s sole discretion, confer sufficient rights to access, operate, construct, modify, maintain, place and remove Transmission Provider owned facilities or is otherwise conveyed using forms unacceptable to Transmission Provider. Further, all real property on which Transmission Provider’s facilities are to be located must be environmentally, physically and operationally acceptable to the Transmission Provider in accordance with Good Utility Practice.

Subject to LGIA Article 5.14, Interconnection Customer is responsible for obtaining all permits required by all relevant jurisdictions for the project, including but not limited to, conditional use permits and construction permits; provided however, Transmission Provider shall obtain, at Interconnection Customer’s cost and schedule risk, the permits necessary to construct Transmission Provider’s facilities that are to be located on real property currently owned or held in fee or right by Transmission Provider.

Subject to applicable provisions in the Agreement and an express written waiver by an authorized officer of Transmission Provider, all of the foregoing permits and real property rights (conferring rights on real property that is environmentally, physically and operationally acceptable to Transmission Provider) shall be acquired as provided herein as a condition to Transmission Provider's contractual obligation to construct or take possession of facilities to be owned by the Transmission Provider under this Agreement. Transmission Provider shall have no liability for any project delays or cost overruns caused by delays in acquiring any of the foregoing permits and/or real property rights, whether such delay results from the failure to obtain such permits or rights or the failure of such permits or rights to meet the requirements set forth herein. Further, any completion dates, if any, set forth herein with regard to Transmission Provider's obligations shall be equitably extended based on the length and impact of any such delays.

With respect to the fiber optic cable on Interconnection Customer's tie line that will be owned by the Transmission Provider, the Interconnection Customer and the Transmission Provider agree that Transmission Provider's ownership and operation of fiber optic cable that is attached to poles or other structures that are owned or maintained by the Interconnection Customer is subject to LGIA Article 5.12, Good Utility Practice, and Transmission Provider's Interconnection Policy 139 (Exhibit 1 to Appendix C to LGIA).

Appendix D To LGIA

Security Arrangements Details

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

Automatic Data Transfer. Throughout the term of this Agreement, Interconnection Customer shall provide the data specified below by automatic data transfer to the Transmission Provider Control Center specified by Transmission Provider or to a Third-Party System Operator designated by Transmission Provider (or both):

From the Interconnection Customer’s collector substation:

- Analogs:
  - Transformer # 1 real power
  - Transformer # 1 reactive power
  - Real power flow through 34.5 kV line feeder breaker 1
  - Reactive power flow through 34.5 kV line feeder breaker 1
  - Real power flow through 34.5 kV line feeder breaker 2
  - Reactive power flow through 34.5 kV line feeder breaker 2
  - Real power flow through 34.5 kV line feeder breaker 3
  - Reactive power flow through 34.5 kV line feeder breaker 3
  - Real power flow through 34.5 kV line feeder breaker 4
  - Reactive power flow through 34.5 kV line feeder breaker 4

- Real power flow through 34.5 kV line feeder breaker 5
- Reactive power flow through 34.5 kV line feeder breaker 5
- Reactive power flow through 34.5 kV reactor breaker T1-R1
- Reactive power flow through 34.5 kV capacitor breaker T1-C1
- Transformer # 2 real power
- Transformer # 2 reactive power
- Real power flow through 34.5 kV line feeder breaker 6
- Reactive power flow through 34.5 kV line feeder breaker 6
- Real power flow through 34.5 kV line feeder breaker 7
- Reactive power flow through 34.5 kV line feeder breaker 7
- Real power flow through 34.5 kV line feeder breaker 8
- Reactive power flow through 34.5 kV line feeder breaker 8
- Real power flow through 34.5 kV line feeder breaker 9
- Reactive power flow through 34.5 kV line feeder breaker 9
- Reactive power flow through 34.5 kV reactor breaker T2-R1
- Reactive power flow through 34.5 kV capacitor breaker T2-C1
- A phase 230 kV transmission voltage
- B phase 230 kV transmission voltage
- C phase 230 kV transmission voltage
- Average Wind speed
- Average Plant Atmospheric Pressure (Bar)
- Average Plant Temperature (Celsius)

- Status:
    - 230 kV breaker T1
    - 34.5 kV collector circuit breaker 1
    - 34.5 kV collector circuit breaker 2
    - 34.5 kV collector circuit breaker 3
    - 34.5 kV collector circuit breaker 4
    - 34.5 kV collector circuit breaker 5
    - 34.5 kV reactor circuit breaker T1-R1
    - 34.5 kV capacitor circuit breaker T1-C1
    - 230 kV breaker T2
    - 34.5 kV collector circuit breaker 6

- o 34.5 kV collector circuit breaker 7
- o 34.5 kV collector circuit breaker 8
- o 34.5 kV collector circuit breaker 9
- o 34.5 kV reactor circuit breaker T2-R1
- o 34.5 kV capacitor circuit breaker T2-C1

Billing Meter Data. Bi-directional revenue meter at the Point of Interconnection will not be configured to allow direct dial-up access by Interconnection Customer. The Transmission Provider will provide alternatives, at the Interconnection Customer's expense, upon request.

Additional Data. Interconnection Customer shall, at its sole expense, provide any additional Generating Facility data reasonably required and necessary for the Transmission Provider to operate the Transmission System in accordance with Good Utility Practice and Exhibit 1 to Appendix C, Facility Interconnection Requirements for Transmission Systems.

Relay and Control Settings

If Interconnection Customer requires modifications to the settings associated with control/protective devices connected to the distribution and/or transmission system, Interconnection Customer will contact PacifiCorp and provide in writing the justification for the proposed modifications. This will allow PacifiCorp to analyze the modifications and ensure there will be no negative impacts to connected systems and customers. Any modifications of control and/or relay settings without review and acknowledgement of acceptance by PacifiCorp will be considered a breach of the Interconnection Agreement and grounds for disconnection from the PacifiCorp system.

Appendix E To LGIA

Commercial Operation Date

This Appendix E is a part of the LGIA between Transmission Provider and Interconnection Customer.

[Date]

[Transmission Provider Address]

Re: _______________ Large Generating Facility

Dear _______________:

On **[Date] [Interconnection Customer]** has completed Trial Operation of Unit No. __. This letter confirms that [Interconnection Customer] commenced Commercial Operation of Unit No. ___ at the Large Generating Facility, effective as of **[Date plus one day]**.

Thank you.

[Signature]

[Interconnection Customer Representative]

Appendix F to LGIA

Addresses for Delivery of Notices and Billings

Notices, Billings and Payments:

Transmission Provider:

US Mail Deliveries: PacifiCorp Transmission Services
Attn: Central Cashiers Office
PO Box 2757
Portland, OR 97208-2757

Other Deliveries: Central Cashiers Office
Attn: PacifiCorp Transmission Services
825 NE Multnomah Street, Suite 550
Portland OR 97232

Phone Number: 503-813-6774

Interconnection Customer:
PacifiCorp
Attn: Mike Saunders
1407 W North Temple
Salt Lake City, UT 84116

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

Director, Transmission Services	503-813-7237
Manager, Transmission Scheduling	503-813-5342
Director, Interconnection Services	503-813-6496
Transmission Business Facsimile	503-813-6893

OASIS Address:
http://www.oasis.pacificorp.com/oasis/ppw/main.htmlx

Interconnection Customer:
PacifiCorp
Attn: Mike Saunders
Telephone: 801-220-4869
Mobile: 909-560-0917
Email: Michael.Saunders@pacificorp.com

Appendix G to LGIA

INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating

plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or “GSU”), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the

fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. Power Factor Design Criteria (Reactive Power)

The following reactive power requirements apply only to a newly interconnecting wind generating plant that has executed a Facilities Study Agreement as of the effective

date of the Final Rule establishing the reactive power requirements for non-synchronous generators in section 9.6.1 of this LGIA (Order No. 827). A wind generating plant to which this provision applies shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

Exhibit 1 to Appendix A to LGIA

One-Line Diagram

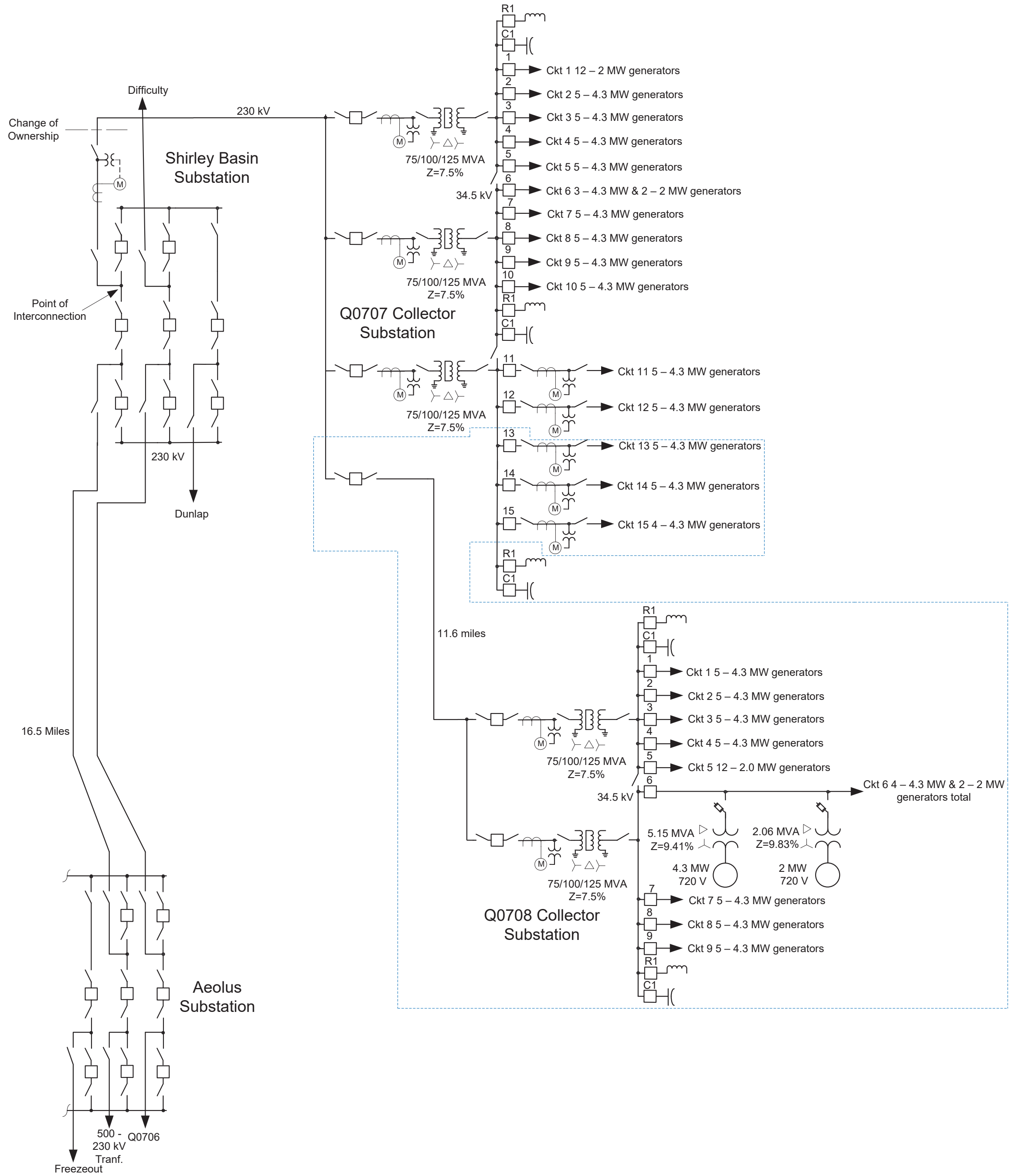


Exhibit 1 to Appendix B to LGIA

Scope of Work

Generating Facility Modifications

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer's Generation Facility.

INTERCONNECTION CUSTOMER TO BE RESPONSIBLE FOR

- Procure all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the Large Generating Facility and collector substation.
- Design, procure, construct, own and maintain the Interconnection Customer's Generating Facility and associated collector substation.
- Procure any necessary agreements to allow the Project to utilize the interconnection facilities associated with the Q0707 project.
- Design the Generating Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer's GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the generating facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Generating Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Transmission Provider.
- Provide data to the Phasor Measurement Unit to be installed at this location by a previous project.

The data must be collected and be able to stream to the Planning Coordinator for each of the Generator Facility’s step-up transformers measured on the low side of the GSU at a sample rate of at least 30 samples per second and synchronized within +/- 2 milliseconds of the Coordinated Universal Time (UTC). Initially, the following data must be collected:

- o Three phase voltage and voltage angle (analog)
- o Three phase current (analog)

Data requirements are subject to change as deemed necessary to comply with local and federal regulations.

- Operate the Generating Facility so as to maintain the voltage at the POI, or other designated point as deemed appropriate by Transmission Provider, at a voltage schedule to be provided by the Transmission Provider following testing.
- Operate the Generating Facility with a voltage droop.
- Participate in any Transmission Provider required studies, such as a voltage coordination study. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Meet the Federal Energy Regulatory Commission (FERC) and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide test results to the Transmission Provider verifying that the inverters for this Project have been programmed to meet all PRC-024 requirements rather than manufacturer IEEE distribution standards.
- Provide the Transmission Provider a standard model from the WECC Approved Dynamic Model Library.
- The Transmission Provider recommends that the Interconnection Customer perform special studies and provide documentation that its turbines have been equipped with SSCI functionality.
- Procure and install a set of line relays to detect and clear faults on the 230 kV line running between the Q0707 and Q0708 collector substations. The relays must be capable of clearing faults in five cycle or less.
- Design, procure, and install a Transmission Provider approved data concentrator to transfer data from the

Interconnection Customer collector substation to the Transmission Provider's RTU located at the POI substation via an optical fiber communications circuit in DNP3 protocol. The Transmission Provider will input and hold the second level passwords for the data concentrator. Password control ensures the Transmission Provider is aware of and is accepting of the changes being requested by the Interconnection Customer.

- Design, procure and install conduit and control cabling and hard wire the Interconnection Customer's source devices to the data concentrator. Replicated values are not acceptable.
- Provide the following points which are based on the Interconnection Customer's most recent design information. Please note that this list of points could change if the Interconnection Customer's final design changes:

  Analogs:
  - Transformer # 1 real power
  - Transformer # 1 reactive power
  - Real power flow through 34.5 kV line feeder breaker 1
  - Reactive power flow through 34.5 kV line feeder breaker 1
  - Real power flow through 34.5 kV line feeder breaker 2
  - Reactive power flow through 34.5 kV line feeder breaker 2
  - Real power flow through 34.5 kV line feeder breaker 3
  - Reactive power flow through 34.5 kV line feeder breaker 3
  - Real power flow through 34.5 kV line feeder breaker 4
  - Reactive power flow through 34.5 kV line feeder breaker 4
  - Real power flow through 34.5 kV line feeder breaker 5
  - Reactive power flow through 34.5 kV line feeder breaker 5
  - Reactive power flow through 34.5 kV reactor breaker T1-R1
  - Reactive power flow through 34.5 kV capacitor breaker T1-C1
  - Transformer # 2 real power
  - Transformer # 2 reactive power

- o Real power flow through 34.5 kV line feeder breaker 6
- o Reactive power flow through 34.5 kV line feeder breaker 6
- o Real power flow through 34.5 kV line feeder breaker 7
- o Reactive power flow through 34.5 kV line feeder breaker 7
- o Real power flow through 34.5 kV line feeder breaker 8
- o Reactive power flow through 34.5 kV line feeder breaker 8
- o Real power flow through 34.5 kV line feeder breaker 9
- o Reactive power flow through 34.5 kV line feeder breaker 9
- o Reactive power flow through 34.5 kV reactor breaker T2-R1
- o Reactive power flow through 34.5 kV capacitor breaker T2-C1
- o A phase 230 kV transmission voltage
- o B phase 230 kV transmission voltage
- o C phase 230 kV transmission voltage
- o Average Wind speed
- o Average Plant Atmospheric Pressure (Bar)
- o Average Plant Temperature (Celsius)

Status:

- o 230 kV breaker T1
- o 34.5 kV collector circuit breaker 1
- o 34.5 kV collector circuit breaker 2
- o 34.5 kV collector circuit breaker 3
- o 34.5 kV collector circuit breaker 4
- o 34.5 kV collector circuit breaker 5
- o 34.5 kV reactor circuit breaker T1-R1
- o 34.5 kV capacitor circuit breaker T1-C1
- o 230 kV breaker T2
- o 34.5 kV collector circuit breaker 6
- o 34.5 kV collector circuit breaker 7
- o 34.5 kV collector circuit breaker 8
- o 34.5 kV collector circuit breaker 9
- o 34.5 kV reactor circuit breaker T2-R1
- o 34.5 kV capacitor circuit breaker T2-C1

- Provide separate graded, grounded and fenced areas along the perimeter of the Interconnection Customer collector substation for the Transmission Provider to install control building. The Transmission Provider’s control building will share a fence and ground grid with the Interconnection Customer's collector substation and have separate, unencumbered access for the Transmission Provider. Fencing, gates and road access shall meet Transmission Provider standards.

- Perform a CDEGS grounding analysis for the Transmission Provider control building site and provide the results to the Transmission Provider.
- Provide AC power to the Transmission Provider's control building for permanent power. Also, design and provide construction and backup retail service.
- Install fiber optic cable in conduit from the Interconnection Customer's data concentrator to the Transmission Provider's control building. The fiber will be terminated in the control building by the Transmission Provider.
- Install fiber optic cable in conduit from the Transmission Provider's control building to a splice box on the Interconnection Customer's transmission tie line. The fiber will be terminated in the control building by the Transmission Provider.
- Design, provide and install complete conduit and control cable from both sets of the Transmission Provider's metering instrument transformers to the Transmission Provider's control building.
- Provide Transmission Provider unfettered and maintained access to both sets of the Transmission Provider's metering instrument transformers.
- Procure and install disconnect switches on each side of each of the Transmission Provider's meters.
- Arrange for and provide permanent retail service for power that will flow from the Transmission Provider's system when the Project is not generating with the retail service provider in this area. This will require the retail service provider to obtain transmission service from the Transmission Provider. These arrangements must be in place prior to approval for backfeed.
- Provide any construction or backup retail service necessary for the Project.
- Procure or construct a Transmission Provider approved redundant communications path from the Transmission Provider's collector substation control building to the POI substation. This redundant path is required as a backup meter data source and must

be separate from the primary fiber optic cable being installed on the transmission tie line.

Transmission Provider to be Responsible For

- Provide the Interconnection Customer the designated point at which the voltage is to be maintained and the associated voltage schedule.
- Identify any necessary studies that the Interconnection Customer must participate in.
- Identify the values to be stored in the PMU.
- Procure and install a control building on the property prepared by the Interconnection Customer adjacent to the Interconnection Customer collector substation.
- Procure and install a backup DC battery system for the Transmission Provider control building.
- Procure and install a communications rack and associated communications equipment in the Transmission Provider's control building and terminate the fiber provided by the Interconnection Customer.
- Design, procure and install 230 kV revenue metering equipment on the high side of each of the Interconnection Customer power transformers including a metering panels, instrument transformers, primary and secondary revenue quality meters, test switches, junction boxes and secondary metering wire at each site.
- Establish an Ethernet connection for retail sales and generation accounting via the MV-90 translation system.

Interconnection Customer Tie Line Requirements

The following outlines the design, procurement, construction, installation, and ownership of equipment associated with the radial line connecting the Interconnection Customer's Generating Facility to the collector substation to be constructed as part of the Interconnection Request assigned queued position Q0707.

Interconnection Customer to be Responsible For

- Procure all necessary permits, property rights and/or the rights of way for the new transmission line between the Interconnection Customer's collector substation and the Q0707 collector substation. Interconnection Customer will be responsible for all required regulatory or compliance reporting associated with its transmission tie line facilities.

- Design, procure, construct, own and maintain the approximately 12 mile 230 kV transmission line between the Interconnection Customer's collector substation and the Q0707 collector substation.
- Design, procure, install, own and maintain Transmission Provider standard OPGW fiber optic cable and associated communications equipment from the Interconnection Customer collector substation to the Q0707 collector substation. One buffer tube with at least 12 fibers shall be provided to the Transmission Provider for its sole use.
- Provide and install fiber splices for the fiber running from both the Transmission Provider's collector substation control building and the POI substation fiber patch panel. The fiber shall be spliced to the Transmission Provider's sole use buffer tube.
- Design around and coordinate with the Transmission Provider regarding any crossings the Interconnection Customer's tie line will have with existing Transmission Provider facilities.

Transmission Provider to be Responsible For

- Coordinate with the Interconnection Customer regarding any crossings the Interconnection Customer's tie line will have with existing Transmission Provider transmission lines.
- Procure and install any required transmission structures to maintain necessary clearance should the Interconnection Customer's tie line cross existing Transmission Provider facilities and are unable to meet clearance requirements.

Q0707 Collector Substation Requirements

The following outlines the design, procurement, construction, installation, and ownership of equipment associated with the collector substation to be constructed as part of the Interconnection Request assigned queue positon Q0707.

Interconnection Customer to be Responsible For

- Procure any necessary agreements to allow the Project to utilize the Q0707 Interconnection Facilities.

- Install two sets of current transformers ("CT") from the Interconnection Customer tie line circuit breaker and provide the output to be fed into the Transmission Provider's POI substation bus differential relays with current transformer ratio matching the CT ratio of the breakers at the POI substation.
- Modify the design of the collector substation such that the expanded portion of the collector substation ground grid supporting the Project can be connected to the POI substation ground grid to support the installation of a Transmission Provider owned and maintained bus differential scheme. The Interconnect Customer is responsible to ensure the ground grid design supports safe step and touch potentials.
- Design, provide and install control cabling (number and size TBD) and hard wire the Interconnection Customer's source devices to the marshalling cabinet. Replicated values are not acceptable.
- Provide and install complete conduit system, as designed by Transmission Provider, from each Transmission Provider metering instrument transformer to the POI substation marshalling cabinet just inside the fence of the POI substation.
- Provide the following data points from the Q0707 collector substation via hardwire to the marshalling cabinet located in the POI substation:

  Analogs:
  - Collector substation Net Generation real power
  - Collector substation Net Generator reactive power
  - Collector substation Interchange energy register
  - Real power flow through 34.5 kV line feeder breaker 13
  - Reactive power flow through 34.5 kV line feeder breaker 13
  - Real power flow through 34.5 kV line feeder breaker 14
  - Reactive power flow through 34.5 kV line feeder breaker 14
  - Real power flow through 34.5 kV line feeder breaker 15
  - Reactive power flow through 34.5 kV line feeder breaker 15

  Status:
  - 230 kV tie line breaker

- o 34.5 kV collector circuit breaker 13
- o 34.5 kV collector circuit breaker 14
- o 34.5 kV collector circuit breaker 15
- Provide Transmission Provider unfettered and maintained access to all of the Transmission Provider's metering instrument transformers.

Transmission Provider to be Responsible For

- Procure, install, own and maintain 34.5 kV instrument transformers on the low side of the Interconnection Customer step up transformer 3 on circuits 13, 14 and 15. Please note that these circuit identification numbers are based on the most recent one line diagram provided to the Transmission Provider. These numbers could change based on the Interconnection Customer's final design.
- Design complete conduit and control cable from each Transmission Provider metering instrument transformers to the POI substation marshalling cabinet just inside the fence of the POI substation.
- Install metering control cable in metering conduit system installed by Interconnection Customer.

Point of Interconnection

The following outlines the design, procurement, construction, installation, and ownership of equipment at the POI.

Interconnection Customer to be Responsible For

- Design, procure, install, own and maintain ADSS fiber optic cable and associated equipment from Interconnection Customer's transmission tie line OPGW splice to POI substation control building as specified by Transmission Provider. This will require the installation of a 3" conduit from the tie line structure splice case to the POI substation fence. At the POI substation, the fiber will be terminated in a Transmission Provider owned and maintained rack. Testing and commissioning of this communication path between the Interconnection Customer's data concentrator device and the POI substation RTU will be the responsibility of the Interconnection Customer and coordinated with the Transmission Provider.

Transmission Provider to be Responsible For

- Design ADSS fiber optic conduit system from the POI substation control building to the OPGW splice. Interconnection Customer will provide and install ADSS from the Tie Line dead end to the POI substation control building.
- Modify existing relay elements to monitor under/over voltage and over/under frequency of the Generating Facility.
- Procure and install the necessary communication equipment to tie data being provided by the Interconnection Customer into the Transmission Provider’s communications network.
- Design, procure and install three sets of 34.5 kV revenue metering equipment to totalize Interconnection Customer circuits 13, 14 and 15 with the Interconnection Customer collector substation generation. This will require two revenue quality meters, test switches, metering panels, junction boxes and secondary metering wire for each circuit.
- Design, provide and install control cabling running from the three sets of instrument transformers installed in the Q0707 collector substation.
- If requested, install a metering cabinet on the exterior of the POI substation fence in order to provide a Modbus or DNP output from the bidirectional meters to the retail service provider. The Transmission Provider will install an underground communication wire from the POI substation control building to the meter panel.
- Establish an Ethernet connection for retail sales and generation accounting via the MV-90 translation system.

Other
The following outlines the design, procurement, construction, installation, and ownership of equipment past the POI.

Transmission Provider to be Responsible For

- Remedial Action Scheme
  - Make the necessary adjustments to the Aeolus RAS assumed to be developed as part of a prior queued project to add the Project. The Project will be tripped for various 500 kV outage scenarios associated with the Transmission Provider’s planned Gateway West and Gateway South

transmission lines. The RAS master controller will be installed in Aeolus substation. Primary communications to the Project will be on the existing fiber optic cable installed on the Aeolus-Shirley Basin #1 transmission line. The redundant communication will be on the fiber optic cable on the Aeolus-Shirley Basin #2 transmission line assumed to be constructed as part of the Q0707 project.

- Develop a new RAS to trip the Project offline for an outage of the Aeolus-Shirley Basin #2 transmission line.
- If necessary, present for approval any generator tripping/load reduction schemes to the WECC Remedial Action Scheme Reliability Subcommittee (“RASRS”).

- Redundant Communications
  - Install any necessary equipment to tie in the Interconnection Customer’s redundant communications link coming from the Interconnection Customer’s collector substation.

- System Operations Centers
  - Update databases for the inclusion of the Interconnection Customer and Transmission Provider Interconnection Facilities and Network Upgrades.

Exhibit 1 to Appendix C to LGIA

Facility Connection Requirements for Transmission Systems

(see attached)

INTERCONNECTION ASSIGNMENT AND ASSUMPTION AGREEMENT

THIS INTERCONNECTION ASSIGNMENT AND ASSUMPTION AGREEMENT (this "Assignment") is dated as of January 2, 2019, and is by and between **PACIFICORP**, an Oregon corporation, acting solely in its resource development capacity ("Assignee") and **INVENERGY WIND DEVELOPMENT LLC,** a Delaware limited liability company ("IWD"), **TB FLATS WIND ENERGY LLC**, a Delaware limited liability company ("TB Flats"), and **TB FLATS WIND ENERGY II LLC,** a Delaware limited liability company ("TB Flats II" and, together with IWD and TB Flats, collectively "Assignor"). Capitalized terms used herein and not defined shall have the same meanings when used herein as in the Purchase Agreement (as hereinafter defined).

RECITALS

WHEREAS, Assignor and Assignee have entered into that certain Development Transfer Agreement, dated as of June 30, 2017 (the "Purchase Agreement"), pursuant to which, among other terms, Assignor has agreed to assign to Assignee all of its right, title and interest in and to the following items as of the date hereof (each of which shall have the meaning ascribed to it in the Purchase Agreement): the interconnection rights described on Exhibit A hereto (collectively, the "Interconnection Assets");

WHEREAS, pursuant to the Purchase Agreement, Assignee shall assume all of the Assumed Liabilities (as defined in the Purchase Agreement) relating to the Interconnection Assets; and

WHEREAS, Assignor and Assignee desire to enter into this Assignment to effect such assignment and assumption.

AGREEMENT

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Assignor and Assignee agree as follows effective as of the Closing:

1. Pursuant to and in accordance with the terms of the Purchase Agreement, Assignor hereby assigns, transfers, sells and conveys to Assignee all of Assignor's right, title and interest in and to the Interconnection Assets, free and clear of all Liens other than Permitted Liens.

2. Pursuant to and in accordance with the terms of the Purchase Agreement, Assignee hereby assumes, and agrees to pay and perform or discharge when due, the Assumed Liabilities relating to the Interconnection Assets.

3. None of the Excluded Assets and none of the Excluded Liabilities are assigned or transferred by Assignor to, or assumed by, Assignee.

4. Unless required by Applicable Law or otherwise agreed to by the Parties after the date hereof, Assignor and Assignee hereby agree that this Assignment and Assumption Agreement shall not be recorded in the public records of any Governmental Entity.

5. This Assignment is intended to evidence the consummation of the transactions contemplated by the Purchase Agreement. This Assignment is made without representation or warranty except as expressly provided herein or as provided in and by the Purchase Agreement. This Assignment is in all respects subject to the provisions of the Purchase Agreement and is not intended in any way to supersede, limit, alter or qualify any obligation in or provision of the Purchase Agreement.

6. Assignor does hereby agree, from time to time as and when reasonably requested by Assignee, to execute and deliver (or cause to be executed and delivered) such documents or instruments and to take (or cause to be taken) such further or other actions, as may be reasonably necessary to carry out the purposes of this Assignment.

7. This Assignment shall be construed, interpreted and the rights of the parties hereto determined in accordance with the Laws of the State of New York without reference to its choice of law provisions.

8. This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and permitted assigns. This Assignment may be executed in counterparts, each of which will be deemed to be an original and all of which together constitute one and the same instrument.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF, Assignor and Assignee have caused this Interconnection Assignment and Assumption Agreement to be duly executed by their respective representatives thereunto duly authorized, all as of the day and year first above written.

ASSIGNOR

Invenergy Wind Development LLC,
a Delaware limited liability company

By:______________________________
Name: James Williams
Title: Vice President

TB Flats Wind Energy LLC,
a Delaware limited liability company

By:______________________________
Name: James Williams
Title: Vice President

TB Flats Wind Energy II LLC,
a Delaware limited liability company

By:______________________________
Name: James Williams
Title: Vice President

ASSIGNEE

PacifiCorp,
an Oregon corporation, solely in its resource development capacity

By:______________________________
Name: Gary Hoogeveen
Title: President & CEO, RMP

CONSENT

PacifiCorp, solely in its transmission capacity and as the "Transmission Provider" and "Transmission Owner" (as such terms are defined in the tendered interconnection agreements for Q707 and Q708), hereby consents to the assignment and assumption of the assigned Interconnection Assets as provided herein.

PacifiCorp,
an Oregon corporation

By:________________________________
Name:
Title:
Date:

EXHIBIT A

TO INTERCONNECTION ASSIGNMENT AND ASSUMPTION AGREEMENT

Interconnection Rights

(a) Any and all of Assignor's rights, title and interest in connection with the tendered interconnection agreements for Q707 and Q708, including (i) any and all amounts deposited with the Transmission Provider by Transmission Customer and (ii) any and all refunds or credits due or owing from the Transmission Provider to Transmission Customer, now or hereafter, and related to the TB Flats I Project or the TB Flats II Project, other than reimbursements under the E&P Agreements (it being acknowledged by the parties that the assignment of the rights set forth in this clause (a) shall not relieve Assignee of its obligations pursuant to Section 7.12 or 9.3(iii) of the DTA);

(b) all rights and obligations under the Engineering and Procurement Agreement, dated September 14, 2018, between PacifiCorp (in its transmission capacity) and Invenergy Wind Development, LLC regarding Q707, and the Engineering and Procurement Agreement, dated September 14, 2018, between PacifiCorp (in its transmission capacity) and Invenergy Wind Development, LLC regarding Q70 (collectively, the "E&P Agreements"), other than the rights to reimbursement for payments made by or on behalf of Assignor thereunder prior to the Closing,

(c) any and all of the assignable rights and interests of Transmission Customer in the TB Flats I Project's and the TB Flats II Project's transmission interconnection queue position;

(d) the application for interconnection of the TB Flats I Project and the TB Flats II Project filed by Transmission Customer with the Transmission Provider;

(e) any studies, reports or other documents regarding the TB Flats I Project or the TB Flats II Project provided by the Transmission Provider or Transmission Owner;

(f) other rights with respect to the tendered interconnection agreements for Q707 and Q708 that the Transmission Customer may have with the Transmission Provider or Transmission Owner, and

(g) any and all other assignable rights relating to the interconnection of the TB Flats I Project or the TB Flats II Project to the transmission grid.

Capitalized terms used in this Exhibit A but not defined in the Purchase Agreement shall have the meanings given to them in the tendered interconnection agreements for Q707 and Q708.

REDACTED
Docket No. UE 374
Exhibit PAC/812
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

TB Flats Easements

February 2020

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

Docket No. UE 374
Exhibit PAC/813
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

TB Flats Permit Status Record

February 2020

TB Flats Wind Energy Project
Wyoming Industrial Siting Permit Conditions Compliance Tracking Table
Overall Permit Status
Wednesday, October 30, 2019

Item ID	Issuing Agency Permit Name	Permit	Details	Status	Open/ Closed
1	FAA	Notice of proposed Construction or Alteration	Receive Notice of Proposed Construction or Alternation (7460-1 Form)	Complete, form 7460-1 approvals were received for all WTG locations and alternative locations	Closed
2	USACE	Clean Water Act Section 404	Clean Water Act - Section 404 Nationwide or Individual Permit (if wetlands or waterways distubed)	Nation wide permti submitted on May 29, 2019	Closed
3	EPA	Spill Prevention Control and Countermeasure (SPCC) Plan	Pending final design, a SPCC will be filed for construction	5-Mar-19	Closed
4	USFWS	Eagle Conservation Plan - Voluntary Guidelines for wind energy projects		Ongoing, plan drafted and being updated. No actual permit issued. Work will continue through the Summary of 2019	Open
5		Bird and Bat Conservation Strategy		Ongoing, plan drafted and being updated. No actual permit issued. Work will continue through the Summary of 2019	Open
6	Department of Commerce - NTIA	Impact to Telecommunication Systems and RADAR's		Complete, NTIA on September 13, 2018 there was no objection to turbine consturction in the design area	Closed
7	FCC	Licensed Microwave Study		Complete	Closed
8	FEMA	Floodplain Considerations	FEMA Flood plan considierations	FEMA has no applicalbe maps; maps of river and creeks has been generated and been reviewed; Structures associated with the TB Flats wind energy project are placed above the 100 year incident mark	Closed
9	WYDEQ	Wyoming ISD Section 109	Wyoming Industrial Development Information and Siting Act, Section 109	Complete, ISD permit was issued on July 30, 2018.	Closed
10		Wyoming Pollutant Discharge Elimination System (WYPDES) - Large Construction Permit	Large Construction General Permit covers water discharges from construction greater than 5 acres.	SWPPP completed n April 10, 2019	Closed
11		Permit to Construction small wastewater facilities	A permit is required for the installation, repair or replacement of small wastewater systems, also known as septic tanks and leach fields. Septic systems that handle more than 2,000 gallons per day require a large capacity septic system permit, which are issued by the Underground Injection Control (UIC) Program.	Ongoing, PacifiCorp and its EPC contractor will be submitting a request for permit in early 2020.	Open
12		Temporary / Portable source air permit/ fugitive dust permit	Tempoarary / Portable source air permit and fugitive dust permit for the project site.	Burnett Quarry WYDEQ Air Quality Permit # CT-2899, we will also be using relocatable permit CT-7415 & RE-1032-2. TB Flats Batch PlantWYDEQ Air Quality Permit #s RE 9984 & RE-208	Closed
13		Mining/quarry permit (non-coal) for gravel quarry and constriction materials		See above	Closed
14		Wetland mitigation permit		Nationwide permit utilized	Closed
15	WSED	Temporary Water Use Agreement		Tempoary water agreement met with landowner	Closed
16		Permit to appropriate groundwater for well for operations & maintenance building		Water agreement met with Q Creek to supply the O&M building	Closed
17	WSHPO	Cultural resources and property review	Clutural resousrces and property review of both state and private property	Review completed March 30, 2019	Closed
18	WOSLI	Special Use lease for wind energy	Wind Energy Lease Agreement (WL-1603)	Complete, Wind Energy Lease executed on August 17, 2017	Closed
19	WYDOT	Port of Entry authorizations for oversized/overweight loads	Apply to the Wyoming Department of Transportation and Highway Patrol for Port of Energy Permission to move oversize/weight loads	Ongoing, Port of Enetry authorixation for oversize/overweight loads, will be obtained by PacifiCorp's WTG supplier prior to the 2020 delivery date	Open

20	WYDOT	Approach permit/Right of ways Access	Apply to the Wyoming Department of Transportation for relocation and right-of-way approval as needed to delivery WTG	Access permits granted on August 7, 2019	Closed
21		State Road Use Agreement	PacifiCorp will acquire a State of Wyoming Department of Transportation Road Use Agreement 30 days prior to construction	Closed, State Road Use Agreement executed on Febrary 22, 2019	Closed
22		*Conditional Use Permit*			
23		COA 2. Notice of material change to project, as needed	Conditional Use Permit is granted for up to 200 wind turbines and accessory uses as generally described in the application. The Applicant(s) shall notify the Carbon County Planning & Development Department in writing of any material changes to the Project subsequent to the County issuance of the Conditional Use Permit.	No action required unless material change is planned.	Open
24		COA 3 . Submit Copy of all Federal and State approvals	This permit is subject to final approval and issuance of a permit by the Industrial Siting Council. The Applicant(s) shall submit a copy of all subsequent Federal and State approvals, including all required studies, reports and certifications prior to the issue of any applicable building permits.	Closed, Submission made on March 25, 2019 and acceppted by Carbon County on April 1	Closed
25		COA 4-5-8. WTG & O&M building permit & Land owner approval & WTG Location	PacifiCorp's contractor will obtain building permits prior to construction	All permits received excluding the O&M building	Open
26		COA 12. Submit detail Site Map (90 days after operation)	To the extent not inconsistent with confidentiality and security obligations under State and\or Federal law, the Owner(s) or Operator(s) shall provide the Carbon County Planning and Development Department with a detailed map of the site within ninety (90) days after operation begins. The Project Map will include the geographic coordinates of each WECS structure, all roads within the WECS Project area, and public roads and turnouts connecting to roads of the WECS Project. The Project Map shall be updated by the Owner(s) or Operator(s) every five (5) years or after the completion of any significant additional construction.	Ongoing, will be submitted once construction is complete	Open
27		COA 13. Annual Proof of Insurance	The Owner(s) or Operator(s) of the WECS Project shall maintain a current General Liability Policy issued by an insurance company authorized to do business in Wyoming covering bodily injury and property damage with limits of at least $1 million per occurrence and $1 million in the aggregate. The Applicant(s) shall provide proof of insurance to the Board of County Commissioners prior to the Board's approval of the submitted application or otherwise demonstrate adequate self-insurance. If the application is approved, the Owner(s) or Operator(s) of the WECS shall provide proof of insurance to the Board annually. Proof of insurance may be made by providing a certificate of insurance	Closed, PacifiCorp submitted proof of insurancce on March 4, 2019	Closed
28		COA 15. PacifiCorp agreement to CUP provisions	No conditional use permit shall be transferred without the prior approval of the Board of County Commissioners. The Board's approval shall not be unreasonably withheld upon good cause shown. Any transferee shall agree in writing to be bound by the terms of the Conditional Use Permit. It is specifically understood and agreed that as of the date of the Carbon County Commission hearing on April 3rd, 2018, the Applicant intends to transfer this permit to PacifiCorp for construction, development, and operation of the Project. The Board hereby approves of such transfer, subject to PacifiCorp agreeing in writing to be bound by all of the terms of the Conditional Use Permit as the owner of the permit. This conditional use permit shall not have any additional transfers other than the aforementioned transfer under this paragraph 14 without the prior approval of the Board of County Commissioners.	Closed, PacifiCorp submitted assignment and agreement letter to Carbon County on January 10, 2019	Closed
29		COA 16. Initial 6 Month Status update and annual P&Z status report and appearance	Within six (6) months of the Board's approval, and on an annual basis thereafter until construction is completed, the permit holder shall provide a progress report of the WECS Project to the County Planning and Zoning Commission. The annual report\progress report shall include a written summary of Project's progress and include an appearance at a regularly scheduled County Planning and Zoning Commission meeting.	Ongoing, Construction Phase	Open
30		*Carbon County Road Use Agreement*			

31	Carbon County	4. Identify haul routes and courting roads to be used	The Company is hereby authorized to operate and move its commercial vehicles on all such Haul Routes and Roads, so long as such use is in accordance with this Agreement. The Haul Routes and County Roads utilized for project must be identified and approved in writing by the Carbon County Superindent of Road and Bridge prior to any construction. Attached hereto as Exhibit A is a list of the restrictions on the Company's use of the Haul Route Roads. The Company shall use commercially reasonable efforts to comply with the restrictions listed on Exhibit A. It is specifically understood and agreed that personal vehicles and other light-duty vehicles will not be bound by the restrictions of Exhibit A	Closed, on February 14, 2019 PacifiCorp notified Carbon County of its planned hual routes	Closed
32		6.a-b. Post security of $50,000 per mile	a) The County may require that the Company post security during construction for repairs that are required by paragraph 9(c) below, in an amount to be specified by the County. b) If the County requires that the Company post security, the Company shall not haul goods, equipment or materials on the Roads forming the Haul Route until: i. II has delivered to the County the security required (in the form of surety bond in the minimum amount of $50,000.00 (Fifty Thousand dollars per mile of affected Carbon County Roads); and ii. A Pre-Inspection pursuant to 7.1 has been completed.	Closed, PacifiCorp provided bonding on March 27, 2019 to Carbon County	Closed
33		7.1 Pre Construction Inspection (15 days before construction)	The Company and the County shall agree as to the condition of the Haul Route Roads both within fifteen (15) days prior to commencement of construction of the Wind power Facilities and within fifteen (15) days following completion of construction of the Wind power Facilities. Video recordings and photographs of the current conditions of the Haul Route Roads will be undertaken by the Company (or a third party hired by the Company), at the Company's expense and provided to the County for its review and retention (i) prior to the start of any construction activities by the Company, and (ii) following the Company's completion of construction of the Windpower Facilities. The County shall have the right, if so desired, (i) to observe these recordings/photographs as they are being taken and (ii) to require the Company to undertake certain types of recordings and photographs or reasonable additional inspections if the County reasonably believes the recordings/photographs are inadequate representations of the impacted roads current conditions.	Closed, Completed on April 15	Closed
34		7.1 Post Construction Inspection (15 after construction)	The Company and the County shall agree as to the condition of the Haul Route Roads both within fifteen (15) days prior to commencement of construction of the Wind power Facilities and within fifteen (15) days following completion of construction of the Wind power Facilities. Video recordings and photographs of the current conditions of the Haul Route Roads will be undertaken by the Company (or a third party hired by the Company), at the Company's expense and provided to the County for its review and retention (i) prior to the start of any construction activities by the Company, and (ii) following the Company's completion of construction of the Windpower Facilities. The County shall have the right, if so desired, (i) to observe these recordings/photographs as they are being taken and (ii) to require the Company to undertake certain types of recordings and photographs or reasonable additional inspections if the County reasonably believes the recordings/photographs are inadequate representations of the impacted roads current conditions.	Ongoing, post construction survey to be conducted	Open
35		11 Assignment	Except as otherwise provided herein, this Agreement shall not be assigned by either party hereto without the prior written consent of the other party, which consent shall not unreasonably be withheld.	Closed , Assignment approved on March 18, 2019 by Carbon County	Closed
36					

Docket No. UE 374
Exhibit PAC/814
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

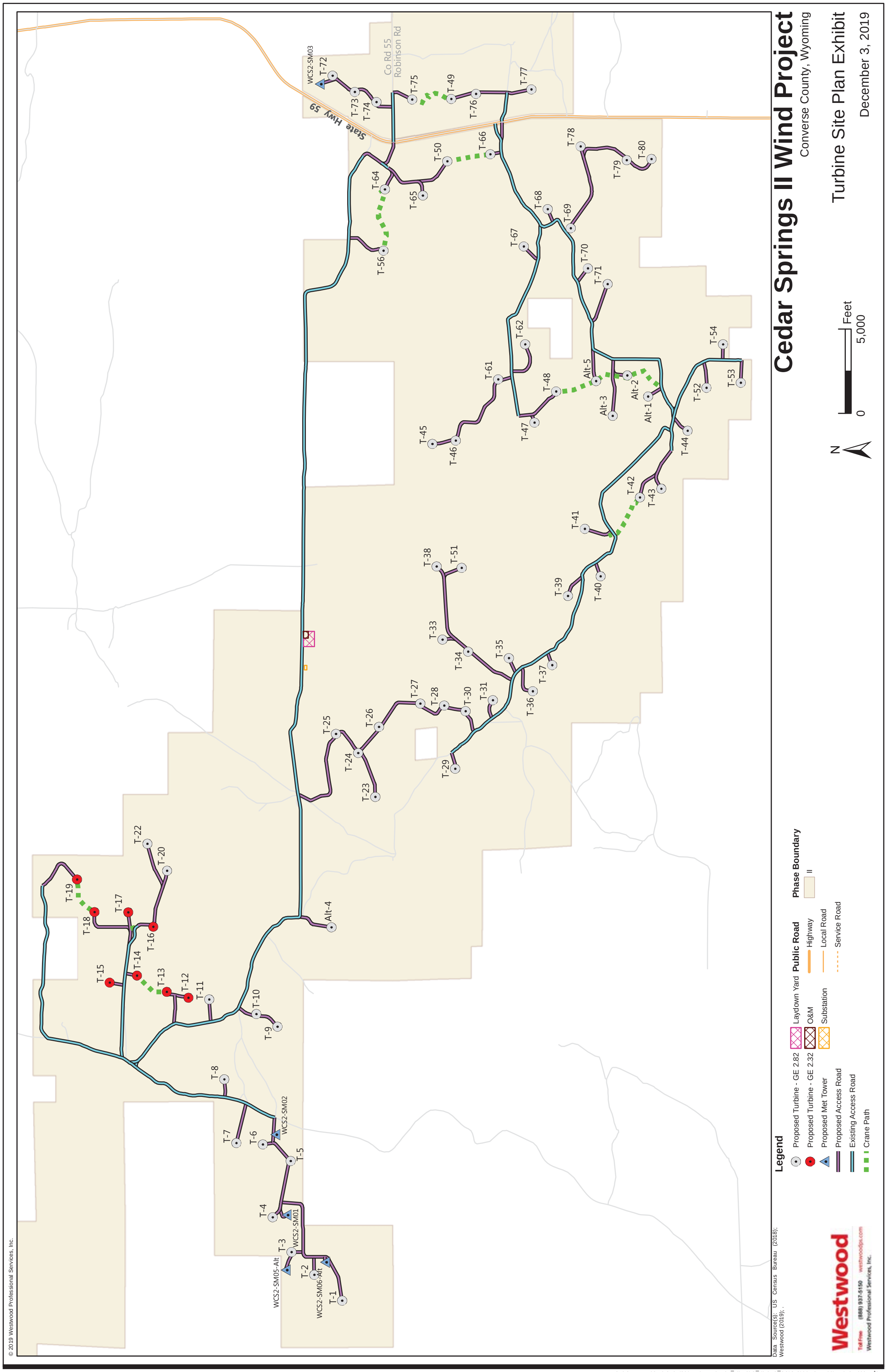
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

Site Plan Cedar Springs

February 2020



Map Document: N:\0014732.00\GIS\CS_Overall_SitePlan_191202.mxd 12/03/19 8:01:50 AM NEOBrien

REDACTED
Docket No. UE 374
Exhibit PAC/815
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

Cedar Springs Assessment and Wind Energy Analysis

February 2020

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

REDACTED
Docket No. UE 374
Exhibit PAC/816
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

Cedar Springs Project Schedule

February 2020

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

Docket No. UE 374
Exhibit PAC/817
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

Large Generator Interconnection Agreement Cedar Springs

February 2020

FIRST AMENDED AND RESTATED
STANDARD LARGE GENERATOR
INTERCONNECTION AGREEMENT (LGIA)
between
PACIFICORP
and
CEDAR SPRINGS WIND, LLC
CEDAR SPRINGS TRANSMISSION LLC
CEDAR SPRINGS WIND III, LLC

CEDAR SPRINGS 1

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STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this ___ day of ____________, 20__ by and between Cedar Springs Wind, LLC, Cedar Springs Transmission LLC, and Cedar Springs Wind III, LLC, limited liability companies organized and existing under the laws of the State of Delaware (collectively referred to as the "Interconnection Customer") with a Large Generating Facility, and PacifiCorp a corporation organized and existing under the laws of the State of Oregon ("Transmission Provider and/or Transmission Owner"). Interconnection Customer and Transmission Provider each may be referred to as a "Party" or collectively as the "Parties."

Recitals

WHEREAS, Transmission Provider operates the Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and,

WHEREAS, Interconnection Customer and Transmission Provider have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility with the Transmission System;

WHEREAS, Cedar Springs Wind, LLC, Cedar Springs Transmission LLC, and Cedar Springs Wind III, LLC agree to act as a single Interconnection Customer under this LGIA according to the terms of Appendix H of this LGIA.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (Tariff).

Article 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the

Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection System Impact Study.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission Provider's Transmission System. The scope of the study is defined in Section 43 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System, the scope of which is described in Section 41 of the Standard Large Generator Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard

Large Generator Interconnection Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

NERC shall mean the North American Electric Reliability Council or its successor organization.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose.

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in the Transmission Provider's Tariff.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating

Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission Provider's Transmission System or on other delivery systems or other generating systems to which the Transmission Provider's Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Large Generator Interconnection Agreement to the extent necessary.

Transmission Provider shall mean the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Variable Energy Resource shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Article 2. Effective Date, Term, and Termination

2.1 Effective Date. This LGIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this LGIA with FERC upon execution in accordance with Article 3.1, if required.

2.2 Term of Agreement. Subject to the provisions of Article 2.3, this LGIA shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as Interconnection Customer may request (Term to be specified in individual agreements) and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures.

2.3.1 Written Notice. This LGIA may be terminated by Interconnection Customer after giving Transmission Provider ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

2.3.2 Default. Subject to the terms set forth in Appendix H, either Party may terminate this LGIA in accordance with Article 17.

2.3.3 Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this LGIA, which notice has been accepted for filing by FERC.

2.4 Termination Costs. If a Party elects to terminate this Agreement pursuant to Article 2.3 above, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party, as of the date of the other Party's receipt of such notice of termination, that are the responsibility of the Terminating Party under this LGIA. In the event of termination by a Party, the Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this LGIA, unless otherwise ordered or approved by FERC:

2.4.1 With respect to any portion of Transmission Provider's Interconnection Facilities that have not yet been constructed or installed, Transmission Provider shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Provider shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Provider for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Provider shall promptly refund such amounts to

Interconnection Customer, less any costs, including penalties incurred by Transmission Provider to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this LGIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which Transmission Provider has incurred expenses and has not been reimbursed by Interconnection Customer.

2.4.2 Transmission Provider may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Provider shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this LGIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 Disconnection. Upon termination of this LGIA, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Transmission System to the extent appropriate giving consideration to whether a replacement LGIA is executed for one or more Customer Signatories (as defined in Attachment H hereto). All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 Survival. This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this LGIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

Article 3. Regulatory Filings

3.1 Filing. Transmission Provider shall file this LGIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this LGIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

Article 4. Scope of Service

4.1 Interconnection Product Options. Interconnection Customer has selected the following (checked) type of Interconnection Service:

X **4.1.1 Energy Resource Interconnection Service.**

4.1.1.1 The Product. Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating

Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interconnection Service, Transmission Provider shall construct facilities identified in Attachment A.

4.1.1.2 **Transmission Delivery Service Implications.** Under Energy Resource Interconnection Service, Interconnection Customer will be eligible to inject power from the Large Generating Facility into and deliver power across the interconnecting Transmission Provider's Transmission System on an "as available" basis up to the amount of MWs identified in the applicable stability and steady state studies to the extent the upgrades initially required to qualify for Energy Resource Interconnection Service have been constructed. Where eligible to do so (e.g., PJM, ISO-NE, NYISO), Interconnection Customer may place a bid to sell into the market up to the maximum identified Large Generating Facility output, subject to any conditions specified in the interconnection service approval, and the Large Generating Facility will be dispatched to the extent Interconnection Customer's bid clears. In all other instances, no transmission delivery service from the Large Generating Facility is assured, but Interconnection Customer may obtain Point-to-Point Transmission Service, Network Integration Transmission Service, or be used for secondary network transmission service, pursuant to Transmission Provider's Tariff, up to the maximum output identified in the stability and steady state studies. In those instances, in order for Interconnection Customer to obtain the right to deliver or inject energy beyond the Large Generating Facility Point of Interconnection or to improve its ability to do so, transmission delivery service must be obtained pursuant to the provisions of Transmission Provider's Tariff. The Interconnection Customer's ability to inject its Large Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of Transmission Provider's Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of firm Point-to-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

☐ **4.1.2 Network Resource Interconnection Service.**

4.1.2.1 The Product. Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as all Network Resources. To the extent Interconnection Customer wants to receive Network Resource Interconnection Service, Transmission Provider shall construct the facilities identified in Attachment A to this LGIA.

4.1.2.2 **Transmission Delivery Service Implications.** Network Resource Interconnection Service allows Interconnection Customer's Large Generating Facility to be designated by any Network Customer under the Tariff on Transmission Provider's Transmission System as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Large Generating Facility in the same manner as it accesses Network Resources. A Large Generating Facility receiving Network Resource Interconnection Service may also be used to provide

Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Large Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Large Generating Facility has not been designated as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or firm Point-to-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Large Generating Facility to any particular load on Transmission Provider's Transmission System without incurring congestion costs. In the event of transmission constraints on

Transmission Provider's Transmission System, Interconnection Customer's Large Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that Interconnection Customer's Large Generating Facility be designated as a Network Resource by a Network Service Customer under the Tariff or that Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does designate the Large Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interconnection Service, any future transmission service request for delivery from the Large Generating Facility within Transmission Provider's Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Large Generating Facility be undertaken, regardless of whether or not such Large Generating Facility is ever designated by a

Network Customer as a Network Resource and regardless of changes in ownership of the Large Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Large Generating Facility outside Transmission Provider's Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

4.2 Provision of Service. Transmission Provider shall provide Interconnection Service for the Large Generating Facility at the Point of Interconnection.

4.3 Performance Standards. Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is a Transmission Provider or Transmission Owner, then that Party shall amend the LGIA and submit the amendment to FERC for approval.

4.4 No Transmission Delivery Service. The execution of this LGIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

4.5 Interconnection Customer Provided Services. The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.5.1.

Interconnection Customer shall be paid for such services in accordance with Article 11.6.

Article 5. Interconnection Facilities Engineering, Procurement, and Construction

5.1 Options. Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either Standard Option or Alternate Option set forth below for completion of Transmission Provider's Interconnection Facilities and Network Upgrades as set forth in Appendix A, Interconnection Facilities and Network Upgrades, and such dates and selected option shall be set forth in Appendix B, Milestones.

5.1.1 Standard Option. Transmission Provider shall design, procure, and construct Transmission Provider's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Provider shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Provider reasonably expects that it will not be able to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the specified dates, Transmission Provider shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable

Efforts to meet the earliest dates thereafter.

5.1.2 **Alternate Option.** If the dates designated by Interconnection Customer are acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities by the designated dates.

If Transmission Provider subsequently fails to complete Transmission Provider's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B, Milestones; Transmission Provider shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable RTO or ISO refuses to grant clearances to install equipment.

5.1.3 **Option to Build.** If the dates designated by Interconnection Customer are not acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission

Provider's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. Transmission Provider and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 Negotiated Option. If Interconnection Customer elects not to exercise its option under Article 5.1.3, Option to Build, Interconnection Customer shall so notify Transmission Provider within thirty (30) Calendar Days, and the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades by Interconnection Customer) pursuant to which Transmission Provider is responsible for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, Transmission Provider shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Network Upgrades pursuant to 5.1.1, Standard Option.

5.2 General Conditions Applicable to Option to Build. If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct

Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Provider;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Provider shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider;

(5) at any time during construction, Transmission Provider shall have the right to gain unrestricted access to Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Provider's Interconnection

Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Provider, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider for claims arising from Interconnection Customer's construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) Interconnection Customer shall transfer control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Provider's Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Provider;

(10) Transmission Provider shall approve and accept for operation and maintenance Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information, and any other documents that are reasonably required by Transmission Provider to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

5.3 Liquidated Damages. The actual damages to Interconnection Customer, in the event Transmission Provider's Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Provider pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Provider to Interconnection Customer in the event that Transmission Provider does not complete any portion of Transmission Provider's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades, in the aggregate, for which Transmission Provider has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades for which Transmission Provider has assumed responsibility to design, procure, and construct. The foregoing payments will be made by Transmission Provider to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Transmission Provider's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for the Large Generating Facility's Trial Operation or to export power from the Large Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of Transmission

Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for Large Generating Facility's Trial Operation or to export power from the Large Generating Facility, but for Transmission Provider's delay; (2) Transmission Provider's failure to meet the specified dates is the result of the action or inaction of Interconnection Customer or any other Interconnection Customer who has entered into an LGIA with Transmission Provider or any cause beyond Transmission Provider's reasonable control or reasonable ability to cure; (3) the interconnection Customer has assumed responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 Power System Stabilizers. The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative. The requirements of this paragraph shall not apply to wind generators.

5.5 Equipment Procurement. If responsibility for construction of Transmission Provider's Interconnection Facilities or Network Upgrades is to be borne by Transmission Provider, then Transmission Provider shall commence design of Transmission Provider's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 Transmission Provider has completed the Facilities Study pursuant to the Facilities Study Agreement;

5.5.2 Transmission Provider has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.5.3 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.6 Construction Commencement. Transmission Provider shall commence construction of Transmission Provider's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Provider's Interconnection Facilities and Network Upgrades;

5.6.3 Transmission Provider has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.6.4 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.7 Work Progress. The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Either Party may, at any time, request a progress report from the other Party. If, at any time, Interconnection Customer determines that the completion of Transmission Provider's Interconnection Facilities will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider of such later date upon which the completion of Transmission Provider's Interconnection Facilities will be required.

5.8 **Information Exchange.** As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with Transmission Provider's Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 **Limited Operation.** If any of Transmission Provider's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Large Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Large Generating Facility and Interconnection Customer's Interconnection Facilities may operate prior to the completion of Transmission Provider's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. Transmission Provider shall permit Interconnection Customer to operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.10 **Interconnection Customer's Interconnection Facilities ('ICIF').** Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.10.1 Interconnection Customer's Interconnection Facility Specifications. Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Provider at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Provider shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 Transmission Provider's Review. Transmission Provider's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Provider, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider.

5.10.3 ICIF Construction. The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission

Provider "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Large Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Large Generating Facility. The Interconnection Customer shall provide Transmission Provider specifications for the excitation system, automatic voltage regulator, Large Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.11 Transmission Provider's Interconnection Facilities Construction. Transmission Provider's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Provider shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Provider's Interconnection Facilities [include appropriate drawings and relay diagrams].

Transmission Provider will obtain control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

5.12 Access Rights. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to the other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the Transmission System; (ii) operate and maintain the Large Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners. If any part of Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Provider or Transmission Owner, Transmission Provider or Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

5.14 Permits. Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission

Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities. Interconnection Customer may request Transmission Provider to construct, and Transmission Provider shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 Suspension. Interconnection Customer reserves the right, upon written notice to Transmission Provider, to suspend at any time all work by Transmission Provider associated with the construction and installation of Transmission Provider's Interconnection Facilities and/or Network Upgrades required under this LGIA with the condition that Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Provider's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Provider (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Provider cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Provider shall obtain Interconnection Customer's authorization to do so.

Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Transmission Provider required under this LGIA pursuant to this Article 5.16, and has not requested Transmission Provider to recommence the work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Transmission Provider, if no effective date is specified.

5.17 Taxes.

5.17.1 Interconnection Customer Payments Not Taxable. The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Provider for the installation of Transmission Provider's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 Representations and Covenants. In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to Transmission Provider for Transmission Provider's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of Transmission Provider's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Transmission Provider's request, Interconnection Customer shall provide Transmission Provider with a report from an independent engineer confirming its representation in clause (iii), above. Transmission Provider represents and covenants that the cost of Transmission Provider's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon the Transmission Provider. Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Transmission Provider from the cost consequences of any current tax liability imposed against Transmission Provider as the result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Transmission Provider.

Transmission Provider shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this LGIA unless (i) Transmission Provider has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Transmission Provider should be reported as income subject to taxation or (ii) any Governmental Authority directs Transmission Provider to report payments or property as income subject to taxation; provided, however, that Transmission Provider may require Interconnection Customer to provide security for Interconnection Facilities, in a form reasonably acceptable to Transmission Provider (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Transmission Provider for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Transmission Provider of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by Transmission Provider upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 **Tax Gross-Up Amount.** Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Interconnection Customer will pay Transmission Provider, in addition to the amount paid for the Interconnection Facilities and Network Upgrades, an amount equal to (1) the current taxes imposed on Transmission Provider ("Current Taxes") on the excess of (a) the gross income realized by Transmission Provider as a result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit Transmission Provider to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Transmission Provider's composite federal and state tax rates at the time the payments or property transfers are received and Transmission Provider will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Transmission Provider's anticipated tax depreciation deductions as a result of such payments or property transfers by Transmission Provider's current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.17.5 Private Letter Ruling or Change or Clarification of Law. At Interconnection Customer's request and expense, Transmission Provider shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Transmission Provider under this LGIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Transmission Provider and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Transmission Provider shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Transmission Provider shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 **Subsequent Taxable Events.** If, within 10 years from the date on which the relevant Transmission Provider's Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this LGIA terminates and Transmission Provider retains ownership of the Interconnection Facilities and Network Upgrades, Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Transmission Provider, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 **Contests.** In the event any Governmental Authority determines that Transmission Provider's receipt of payments or property constitutes income that is subject to taxation, Transmission Provider shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Transmission Provider may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Transmission Provider reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Transmission Provider shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Transmission Provider may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Transmission Provider, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Transmission Provider for the tax at issue in the contest.

5.17.8 **Refund.** In the event that (a) a private letter ruling is issued to Transmission Provider which holds that any amount paid or the value of any property transferred by Interconnection Customer to

Transmission Provider under the terms of this LGIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Transmission Provider in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not taxable to Transmission Provider, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Transmission Provider are not subject to federal income tax, or (d) if Transmission Provider receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Transmission Provider pursuant to this LGIA, Transmission Provider shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by Interconnection Customer to Transmission Provider for such taxes which Transmission Provider did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Transmission Provider refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Transmission Provider, any refund or credit Transmission Provider receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to Transmission Provider for such overpayment of taxes (including any reduction in interest otherwise payable by Transmission Provider to any Governmental Authority resulting from an offset or credit); provided, however, that Transmission Provider will remit such amount promptly to Interconnection Customer only after and to the extent that Transmission Provider has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to Transmission Provider's Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 Taxes Other Than Income Taxes. Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Provider for which Interconnection

Customer may be required to reimburse Transmission Provider under the terms of this LGIA. Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Transmission Provider shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Transmission Provider for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Provider.

5.17.10 Transmission Owners Who Are Not Transmission Providers. If Transmission Provider is not the same entity as the Transmission Owner, then (i) all references in this Article 5.17 to Transmission Provider shall be deemed also to refer to and to include the Transmission Owner, as appropriate, and (ii) this LGIA shall not become effective until such Transmission Owner shall have agreed in writing to assume all of the duties and obligations of Transmission Provider under this Article 5.17 of this LGIA.

5.18 Tax Status. Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this LGIA is intended to adversely affect any Transmission Provider's tax exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General. Either Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, that Party shall provide to the other Party sufficient information regarding such modification so that the other Party may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Large Generating Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Provider shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Provider's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 Standards. Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 Modification Costs. Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Provider makes to Transmission Provider's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Provider's Interconnection Facilities or the Transmission System, or to provide transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

Article 6. Testing and Inspection

6.1 Pre-Commercial Operation Date Testing and Modifications. Prior to the Commercial Operation Date, Transmission Provider shall test Transmission Provider's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Large Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Large

Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications. Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Large Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 Right to Observe Testing. Each Party shall notify the other Party in advance of its performance of tests of its Interconnection Facilities. The other Party has the right, at its own expense, to observe such testing.

6.4 Right to Inspect. Each Party shall have the right, but shall have no obligation to: (i) observe the other Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of the other Party's System Protection Facilities and other protective equipment; and (iii) review the other Party's maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. A Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Party. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this LGIA.

Article 7. Metering

7.1 General. Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Provider shall install Metering Equipment at the Point of Interconnection prior to any operation of the Large Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Large Generating Facility shall be measured at or, at Transmission Provider's option, compensated to, the Point of Interconnection. Transmission Provider shall provide metering quantities, in analog and/or digital form, to Interconnection Customer upon request. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 Check Meters. Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Provider's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Provider or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 Standards. Transmission Provider shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

7.4 Testing of Metering Equipment. Transmission Provider shall inspect and test all Transmission Provider-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Transmission Provider shall, at Interconnection Customer's expense, inspect or test Metering

Equipment more frequently than every two (2) years. Transmission Provider shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Provider's failure to maintain, then Transmission Provider shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission Provider shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

7.5 **Metering Data**. At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Provider and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Large Generating Facility to the Point of Interconnection.

Article 8. Communications

8.1 **Interconnection Customer Obligations**. Interconnection Customer shall maintain satisfactory operating communications with Transmission Provider's Transmission System dispatcher or representative designated by Transmission Provider. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Large

Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Provider as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Large Generating Facility to the location(s) specified by Transmission Provider. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 Remote Terminal Unit. Prior to the Initial Synchronization Date of the Large Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Provider at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Provider through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Provider. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Provider.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 No Annexation. Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4 Provision of Data from a Variable Energy Resource. The Interconnection Customer whose Generating Facility is a Variable Energy Resource shall provide meteorological and forced outage data to the Transmission Provider to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The Interconnection Customer with a Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, wind speed, wind direction, and atmospheric pressure. The Interconnection Customer with a Variable Energy Resource having solar as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission Provider and Interconnection Customer whose Generating Facility is a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility is a Variable Energy Resource also shall submit data to the Transmission Provider regarding all forced outages to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Such requirements for meteorological and forced outage data are set forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

Article 9. Operations

9.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 **Control Area Notification**. At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider in writing of the Control Area in which the Large Generating Facility will be located. If Interconnection Customer elects to locate the Large Generating Facility in a Control Area other than the Control Area in which the Large Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Control Area.

9.3 **Transmission Provider Obligations.** Transmission Provider shall cause the Transmission System and Transmission Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA. Transmission Provider may provide operating instructions to Interconnection Customer consistent with this LGIA and Transmission Provider's operating protocols and procedures as they may change from time to time. Transmission Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

9.4 **Interconnection Customer Obligations**. Interconnection Customer shall at its own expense operate, maintain and control the Large Generating

Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA. Interconnection Customer shall operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this LGIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Either Party may request that the other Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this LGIA.

9.5 Start-Up and Synchronization. Consistent with the Parties' mutually acceptable procedures, Interconnection Customer is responsible for the proper synchronization of the Large Generating Facility to Transmission Provider's Transmission System.

9.6 Reactive Power and Primary Frequency Response.

9.6.1 Power Factor Design Criteria. Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis. The requirements of this paragraph shall not apply to wind generators.

9.6.1.1 Synchronous Generation. Interconnection Customer shall design the Large Generating Facility to maintain a composite power deliver at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all synchronous generators in the Control Area on a comparable basis.

9.6.1.2 Non-Synchronous Generation. Interconnection Customer shall design the Large Generating Facility to maintain composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all non-synchronous generators in the Control Area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of the Final Rule establishing this requirement (Order No. 827).

9.6.2 Voltage Schedules. Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Transmission Provider shall require Interconnection Customer to operate the Large Generating Facility to produce or absorb reactive power within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Provider's voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. Transmission Provider shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance, and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Large Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the System Operator.

9.6.2.1 Voltage Regulators. Whenever the Large Generating Facility is operated in parallel with the Transmission System and voltage regulators are capable of operation, Interconnection Customer shall operate the Large Generating Facility with its voltage regulators in automatic operation. If the Large Generating Facility's voltage regulators are not capable of such automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative, and ensure that such Large Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Large Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Control Area on a comparable basis.

9.6.3 Payment for Reactive Power. Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Large Generating Facility when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1, provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed.

9.6.4 Primary Frequency Response. Interconnection Customer shall ensure the primary frequency response capability of its Large Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term “functioning governor or equivalent controls” as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Large Generating Facility’s real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Large Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Large Generating Facility’s real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Large Generating Facility’s real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC

Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Large Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Interconnection Customer shall operate the Large Generating Facility consistent with the provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Large Generating Facilities.

9.6.4.1 Governor or Equivalent Controls. Whenever the Large Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Large Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection

Customer needs to operate the Large Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Large Generating Facility's governor or equivalent controls to a minimum whenever the Large Generating Facility is operated in parallel with the Transmission System.

9.6.4.2 Timely and Sustained Response. Interconnection Customer shall ensure that the Large Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Large Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Large Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

9.6.4.3 Exemptions. Large Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement. Large Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 9.6.4, but shall be otherwise exempt from the operating requirements in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.4 of this Agreement.

9.6.4.4 Electric Storage Resources. Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Appendix C of its LGIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.3 of this Agreement. Appendix C shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Appendix C must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer’s electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 9.6.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer’s electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer’s electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination. Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to the Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Party of such removal.

9.7.1.2 Outage Schedules. Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Large Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

9.7.1.3 Outage Restoration. If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects the other Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Party, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

9.7.2 **Interruption of Service.** If required by Good Utility Practice to do so, Transmission Provider may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Provider;

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Large Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 **Under-Frequency and Over Frequency Conditions.** The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability of the Transmission System. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

9.7.4 System Protection and Other Control Requirements.

9.7.4.1 System Protection Facilities. Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Provider's Interconnection Facilities or the Transmission System as a result of the interconnection of the Large Generating Facility and Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in

Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

9.7.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 Requirements for Protection. In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Provider's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Large Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Large Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Large Generating Facility.

9.7.6 Power Quality. Neither Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

9.8 Switching and Tagging Rules. Each Party shall provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in

obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Provider's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or Transmission Provider's Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

Article 10. Maintenance

10.1 Transmission Provider Obligations. Transmission Provider shall maintain the Transmission System and Transmission Provider's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.2 Interconnection Customer Obligations. Interconnection Customer shall maintain the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.3 Coordination. The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Large Generating Facility and the Interconnection Facilities.

10.4 Secondary Systems. Each Party shall cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Party. Each Party shall provide advance notice to the other Party before undertaking any work on such circuits, especially on electrical circuits involving circuit

breaker trip and close contacts, current transformers, or potential transformers.

10.5 Operating and Maintenance Expenses. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Provider's Interconnection Facilities.

Article 11. Performance Obligation

11.1 Interconnection Customer Interconnection Facilities. Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

11.2 Transmission Provider's Interconnection Facilities. Transmission Provider or Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Provider's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

11.3 Network Upgrades and Distribution Upgrades. Transmission Provider or Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades. The Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless Transmission Provider or Transmission Owner elects to fund the capital for the Network Upgrades, they shall

be solely funded by Interconnection Customer. In the event that Transmission Provider must change the voltage levels of a discrete portion of the Transmission System to which the Interconnection Customer is connected, Transmission Provider shall give reasonable notice of such change and the Interconnection Customer shall be solely responsible for all costs related to upgrades or modifications to Interconnection Customer's Interconnection Facilities resulting from Transmission Provider's increase in the voltage levels of the Transmission System, in order to remain interconnected with the Transmission System at the new operating voltage. To the extent that the modifications necessary to upgrade Interconnection Facilities qualify as Network Upgrades, Transmission Provider shall be solely responsible for the expense of such modifications or upgrades.

11.4 Transmission Credits.

11.4.1 Repayment of Amounts Advanced for Network Upgrades. Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to Transmission Provider and Affected System Operator, if any, for the Network Upgrades, including any tax gross-up or other tax-related payments associated with Network Upgrades, and not refunded to Interconnection Customer pursuant to Article 5.17.8 or otherwise, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Large Generating Facility. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC=s regulations at 18 C.F.R. § 35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph.

Interconnection Customer may assign such repayment rights to any person.

Notwithstanding the foregoing, Interconnection Customer, Transmission Provider, and Affected System Operator may adopt any alternative payment schedule that is mutually agreeable so long as Transmission Provider and Affected System Operator take one of the following actions no later than five years from the Commercial Operation Date: (1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or (2) declare in writing that Transmission Provider or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full reimbursement shall not extend beyond twenty (20) years from the Commercial Operation Date.

If the Large Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, Transmission Provider and Affected System Operator shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the Generating Facility, if different, is responsible for identifying the entity to which reimbursement must be made.

11.4.2 Special Provisions for Affected Systems. Unless Transmission Provider provides, under the LGIA, for the repayment of

amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

11.4.3 Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Large Generating Facility.

11.5 Provision of Security. At least thirty (30) Calendar Days prior to the commencement of the first of the following to occur: design, procurement, installation, or construction of a discrete portion of a Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and shall be

reduced on a dollar-for-dollar basis for payments made to Transmission Provider for these purposes.

In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must indicate that it would only expire upon final payment made to Transmission Provider to cover all relevant costs for designing, procuring, installing, and constructing the applicable portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which the letter of credit was provided.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must indicate that it would only expire upon final payment made to Transmission Provider to cover all relevant costs for designing, procuring, installing, and constructing the applicable portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which the surety bond was provided.

11.6 Interconnection Customer Compensation. If Transmission Provider requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this LGIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to an RTO or ISO FERC-approved rate schedule. Interconnection Customer

shall serve Transmission Provider or RTO or ISO with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this LGIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

11.6.1 Interconnection Customer Compensation for Actions During Emergency Condition. Transmission Provider or RTO or ISO shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.6.

Article 12. Invoice

12.1 General. Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this LGIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice. Within six months after completion of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades, Transmission Provider shall provide an invoice of the final cost of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades and shall set forth such costs in sufficient

detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this LGIA.

12.4 Disputes. In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide Interconnection Service under this LGIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii).

Article 13. Emergencies

13.1 Definition. "Emergency Condition" shall mean a condition or situation: (i) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (ii) that, in the case

of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, Transmission Provider's Interconnection Facilities or the Transmission Systems of others to which the Transmission System is directly connected; or (iii) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Large Generating Facility or Interconnection Customer's Interconnection Facilities' System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by this LGIA to possess black start capability.

13.2 Obligations. Each Party shall comply with the Emergency Condition procedures of the applicable ISO/RTO, NERC, the Applicable Reliability Council, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

13.3 Notice. Transmission Provider shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Provider's Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Transmission Provider promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Provider's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Provider's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall

be followed as soon as practicable with written notice.

13.4 Immediate Action. Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Provider, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or otherwise regarding the Transmission System.

13.5 Transmission Provider Authority.

13.5.1 General. Transmission Provider may take whatever actions or inactions with regard to the Transmission System or Transmission Provider's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Provider's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a

reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Large Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 Reduction and Disconnection. Transmission Provider may reduce Interconnection Service or disconnect the Large Generating Facility or Interconnection Customer's Interconnection Facilities, when such, reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of Transmission Provider pursuant to Transmission Provider's Tariff. When Transmission Provider can schedule the reduction or disconnection in advance, Transmission Provider shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection Customer and Transmission Provider. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities, and the Transmission System to their normal

operating state as soon as practicable consistent with Good Utility Practice.

13.6 Interconnection Customer Authority. Consistent with Good Utility Practice and the LGIA and the LGIP, Interconnection Customer may take actions or inactions with regard to the Large Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Provider's Interconnection Facilities. Transmission Provider shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.7 Limited Liability. Except as otherwise provided in Article 11.6.1 of this LGIA, neither Party shall be liable to the other for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

Article 14. Regulatory Requirements and Governing Law

14.1 Regulatory Requirements. Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this LGIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act, the Public Utility Holding Company

Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

Article 15. Notices.

15.1 General. Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Either Party may change the notice information in this LGIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given

in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Party in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

Article 16. Force Majeure

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

Article 17. Default

17.1 Default

17.1.1 General. No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act of omission of the other Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 Right to Terminate. If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this LGIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this LGIA.

Article 18. Indemnity, Consequential Damages and Insurance

18.1 Indemnity. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this LGIA on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnified Party.

18.1.1 Indemnified Person. If an Indemnified Person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such Indemnified Person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 Indemnifying Party. If an Indemnifying Party is obligated to indemnify and hold any Indemnified Person harmless under this Article 18, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

18.1.3 Indemnity Procedures. Promptly after receipt by an Indemnified Person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Person shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the Indemnifying Party and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the Indemnifying Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses.

The Indemnified Person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the Indemnified Person and the Indemnifying Party, in such event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be reasonably withheld, conditioned or delayed.

18.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 Insurance. Each party shall, at its own expense, maintain in force throughout the period of this LGIA, and until released by the other Party, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this LGIA.

18.3.9 Within ten (10) days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, each Party shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

Article 19. Assignment

19.1 Assignment. With the exception of the assignment described in Appendix H, clause (d), which assignment the Transmission Provider has already consented to, this LGIA may be assigned by either Party only with the written consent of the other; provided that either Party may assign this LGIA without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this LGIA; and provided further that Interconnection Customer shall have the right to assign this LGIA, without the consent of Transmission Provider, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that Interconnection Customer will promptly notify Transmission Provider of any such assignment. Any financing arrangement entered into by Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured Party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider of the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

Article 20. Severability

20.1 Severability. If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Provider) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

Article 21. Comparability

21.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

Article 22. Confidentiality

22.1 Confidentiality. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 Term. During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of the LGIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

22.1.3 Release of Confidential Information. Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential

Information in contravention of this Article 22.

22.1.4 **Rights.** Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 **No Warranties.** By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 **Standard of Care.** Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this LGIA or its regulatory requirements.

22.1.7 **Order of Disclosure.** If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such

request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this LGIA.

Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 **Termination of Agreement.** Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

22.1.9 **Remedies.** The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants

contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 **Disclosure to FERC, its Staff, or a State.** Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 CFR section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this LGIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party

claims is competitively sensitive, commercial or financial information under this LGIA ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

Article 23. Environmental Releases

23.1 Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the

Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

Article 24. Information Requirements

24.1 Information Acquisition. Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 Information Submission by Transmission Provider. The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 Updated Information Submission by Interconnection Customer. The updated information submission by Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Trial Operation. Interconnection Customer shall submit a completed copy of the Large Generating Facility data

requirements contained in Appendix 1 to the LGIP. It shall also include any additional information provided to Transmission Provider for the Feasibility and Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study Agreement between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on Transmission Provider Transmission System based on the actual data submitted pursuant to this Article 24.3. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

24.4 Information Supplementation. Prior to the Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Large Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Large Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Large Generating Facility to verify proper operation of the Large Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Large Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent change in Large Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the

responses of Large Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Large Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Large Generating Facility terminal or field voltages is provided. Large Generating Facility testing shall be conducted and results provided to Transmission Provider for each individual generating unit in a station.

Subsequent to the Operation Date, Interconnection Customer shall provide Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Provider shall provide Interconnection Customer any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Provider-owned substation that may affect Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

Article 25. Information Access and Audit Rights

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Party information that is in the possession of the disclosing Party and is necessary in order for the other Party to: (i) verify the costs incurred by the disclosing Party for which the other Party is responsible under this LGIA; and (ii) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA.

25.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Party when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The

Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this LGIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this LGIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party, to audit at its own expense the other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this LGIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this LGIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of Transmission Provider's Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission

Provider's issuance of a final invoice in accordance with Article 12.2.

25.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to either Party's performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

25.5 Audit Results. If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

Article 26. Subcontractors

26.1 General. Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

26.2 Responsibility of Principal. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Provider be liable for the actions or

inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

Article 27. Disputes

27.1 Submission. In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 External Arbitration Procedures. Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third

arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail.

27.3 Arbitration Decisions. Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

27.4 Costs. Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

Article 28. Representations, Warranties, and Covenants

28.1 General. Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 Authority. Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 No Conflict. The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any

judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 **Consent and Approval.** Such Party has sought or obtained, or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

Article 29. Joint Operating Committee

29.1 Joint Operating Committee. Except in the case of ISOs and RTOs, Transmission Provider shall constitute a Joint Operating Committee to coordinate operating and technical considerations of Interconnection Service. At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Interconnection Customer shall notify Transmission Provider of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of either Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this LGIA. Each Party shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

29.1.1 Establish data requirements and operating record requirements.

29.1.2 Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

29.1.3 Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Provider's and Interconnection Customer's facilities at the Point of Interconnection.

29.1.4 Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Large Generating Facility and other facilities that impact the normal operation of the interconnection of the Large Generating Facility to the Transmission System.

29.1.5 Ensure that information is being provided by each Party regarding equipment availability.

29.1.6 Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

Article 30. Miscellaneous

30.1 Binding Effect. This LGIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts. In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties. Notwithstanding the foregoing, the Parties agree to be bound by the provisions of Appendix H to this LGIA, and such provisions shall prevail to the extent there is a conflict between the body of this LGIA and Appendix H.

30.3 Rules of Interpretation. This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix to this LGIA, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 Entire Agreement. This LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this LGIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this LGIA.

30.5 No Third Party Beneficiaries. This LGIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 Waiver. The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party. Any waiver at any time by either Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this LGIA. Termination or Default of this LGIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 Headings. The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

30.8 Multiple Counterparts. This LGIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment. The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by the Parties.

30.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. Transmission Provider shall have the right to make a unilateral filing with FERC to modify this LGIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

IN WITNESS WHEREOF, the Parties have executed this LGIA in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

PACIFICORP

By: ______________________________
Rick Vail
Title: VP, Transmission

Date: ______________________________

CEDAR SPRINGS WIND, LLC

By: ______________________________

Title: Michael O'Sullivan
Vice President

Date: 7/1/2019

CEDAR SPRINGS TRANSMISSION LLC

By: ______________________________

Title: Michael O'Sullivan
Vice President

Date: 7/1/2019

CEDAR SPRINGS WIND III, LLC

By: ______________________________

Title: Michael O'Sullivan
Vice President

Date: 7/1/2019

Appendix A to LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

1. Interconnection Facilities:

(a) Interconnection Customer's Interconnection Facilities: consists of approximately 21.6 miles of tie line between Interconnection Customer's Collector Station #1 and the Windstar substation

(b) Transmission Provider's Interconnection Facilities: consists of a new line position and appurtenant equipment (structures, switches, metering) at Windstar substation. Also includes metering for Collector Station #1 and Collector Station #2.

2. Network Upgrades:

(a) Stand Alone Network Upgrades: None

(b) Other Network Upgrades: substation expansion and installation of a new circuit breaker at Windstar substation, new relaying and communications equipment at Aeolus and Shirley Basin substations, new relaying at Standpipe substation, new circuit breakers and switches at Freezeout substation, and reconductoring the Aeolus-Shirley Basin (16 miles), Aeolus-Freezeout (3.5 miles), and the Freezeout-Standpipe (11.5 miles) transmission lines.

3. Distribution Upgrades: None

4. Contingent Facilities: As identified in the Facilities Study for this project dated February 21, 2019 the following Network Upgrades are required to be in-service prior to this project:

- Portions of the Transmission Provider's Energy Gateway Transmission Projects
  - Gateway West segment D2 (Aeolus-Anticline/Bridger) 500 kV transmission line. (2020)
  - A Remedial Action Scheme ("RAS") that will drop approximately 600 MW of generation for various 500

kV outages. (2020)

- A new 230 kV transmission line between Shirley Basin and Aeolus substations assigned to a higher queued project. (2020)

5. Point of Interconnection ("POI"): The point at which Transmission Provider Interconnection Facilities connect to the substation bus at the Windstar substation (see Exhibit 1 to Appendix A).

6. Point of Change of Ownership: The point at which Interconnection Customer and Transmission Provider Interconnection Facilities meet (see Exhibit 1 to Appendix A)

7. One-Line Diagram: is attached to this agreement as Exhibit 1 to Appendix A.

8. Estimated Project Cost: $63,132,000
Direct Assigned: $1,474,000
Network Upgrade: $61,658,000

Appendix B To LGIA
Milestones

Engineering and Procurement Agreement Executed
September 18, 2018

Transmission Provider Commences Engineering and Procurement Activities
September 19, 2018

Interconnection Customer Executes Interconnection Agreement
March 29, 2019

†Interconnection Customer Provision of Financial Security
March 11, 2019

Transmission Provider Engineering Design Complete
May 10, 2019

Interconnection Customer Authorizes Construction
June 1, 2019

Transmission Provider Acquired Property/Permits/ROW Complete
June 15, 2019

All Interconnection Customer Property/Permits/ROW Required for Transmission Provider Scope of Work on Interconnection Customer Side of Point of Interconnection Procured
June 27, 2019

Transmission Provider Construction Begins
July 1, 2019

Interconnection Customer Provides Final Design Information
August 1, 2019

*Energy Imbalance Market Modeling Data Submittal
October 5, 2019

All Interconnection Customer Property/Permits/ROW Procured
November 15, 2019

Transmission Provider Construction Complete
June 8, 2020

Transmission Provider Commissioning Complete
July 6, 2020

Transmission Provider Commissioning Document Review Complete
July 13, 2020

Interconnection Customer's Facilities Receive Backfeed Power
July 15, 2020

**Contingent Projects Complete
October 31, 2020

Initial Synchronization/Generation Testing
November 1, 2020

Commercial Operation
November 15, 2020

†Financial Security determined to be $10,470,000

*Any design modifications to the Interconnection Customer's Generating Facility after this date requiring updates to the Transmission Provider's network model will result in a minimum of 3 months added to all future milestones including Commercial Operation.

**The Contingent Facilities summarized in Appendix A of this LGIA must be in-service prior to the commencement of generation activities.

Appendix C To LGIA

Interconnection Details

Description of the Large Generating Facility: The Large Generating Facility consists of one hundred eighty-nine (189) GE 2.52 and nineteen (19) GE 2.3 turbines connected to eight (8) 34.5 kV strings for a total generation output of 520 MW as measured at the POI.

- Collector Station #1 has four strings of turbines (117x 2.52 turbines and 11x 2.3 turbines) and one string of 4x 16 MVAR capacitors:
  - 44x 2.52 and 4x 2.3 turbines attached to a 84/112/140 MVA (Z=8%) transformer
  - 73x 2.52 and 7x 2.3 turbines and the capacitors attached to a 135/180/225 MVA (Z=8.5%) transformer
- Collector Station #2 has four strings of turbines (72x 2.52 turbines and 8x 2.3 turbines)
  - All strings attached to a single 135/180/225 MVA (Z=8.5%) transformer

The Collector stations are connected by a 6.1 mile tie line, each transformer has a high side circuit breaker, and a secondary breaker on the connecting tie line.

.

The Large Generating Facility is located in Converse County, Wyoming.

Please see Exhibit 1 to Attachment A.

Control Area Requirements: Interconnection Customer shall interconnect and operate the Large Generating Facility in accordance with the Transmission Provider's Facility Interconnection Requirements for Transmission Systems, as may be revised from time to time, attached hereto as Exhibit 1 to Appendix C and by this reference incorporated herein.

Interconnection Details:
Metering. With reference to Article 7.1, Transmission Provider will own and maintain the bi-directional revenue Metering Equipment in Transmission Provider's Point of Interconnection substation at the Interconnection Customer's expense.

Under Frequency and Over Frequency Conditions. Consistent with LGIA Article 9.7.3, Transmission Provider shall design, procure, install and maintain frequency and voltage protection to trip feeder breakers in accordance with the settings shown in Exhibit 1 to Appendix C.

Reactive Power and Voltage Schedule. All interconnecting synchronous and non-synchronous generators are required to design their Generating Facilities with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices. For non-synchronous generators, the power factor requirement is to be measured at the high-side of the generator substation. The Generating Facility must provide dynamic reactive power to the system over the full range of real power output. If the Generating Facility is not capable of providing positive reactive support (i.e., supplying reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations, the facility will be required to add dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.

Generators shall be equipped with automatic voltage-control equipment and normally operated with the voltage regulation control mode enabled unless written authorization, or directive, from the Transmission Provider is given to operate in another control mode (e.g., constant power factor control). The control mode of generating units shall be accurately represented in operating studies. The generators shall be capable of operating continuously at their rated power output within +/- 5% of its rated terminal voltage. Phasor Measurement Units will be required at any Generating Facilities with an individual or aggregate nameplate capacity of 75 MVA or greater.

As required by NERC standard VAR-001-1a, the Transmission Provider will provide a voltage schedule for the Point of Interconnection. In general, Generating Facilities should be operated so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Transmission Provider, in accordance with Transmission Provider Policy 139.

Generating Facilities capable of operating with a voltage droop are required to do so. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer's responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing. If the need for a master controller is identified, the cost and all related installation requirements will be the responsibility of the Interconnection Customer. Participation by the Generation Facility in subsequent interaction/coordination studies will be required pre- and post-commercial operation in order ensure system reliability.

All generators must meet the Federal Energy Regulatory Commission (FERC) and WECC low voltage ride-through requirements.

As the Transmission Provider cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

<u>Property Requirements</u>. Subject to LGIA Articles 5.12 and 5.13, Interconnection Customer is required to obtain for the benefit of Transmission Provider at Interconnection Customer's sole cost and expense all real property rights, including but not limited to fee ownership, easements and/or rights of way, as applicable, for Transmission Provider owned facilities using forms acceptable to Transmission Provider. Transmission Provider shall not be obligated to accept any such real property right that does not, at Transmission Provider's sole discretion, confer sufficient rights to access, operate, construct, modify, maintain, place and remove Transmission Provider owned facilities or is otherwise conveyed using forms unacceptable to Transmission Provider. Further, all real property on which Transmission Provider's facilities are to be located must be environmentally, physically and operationally acceptable to the Transmission Provider in accordance with Good Utility Practice.

Subject to LGIA Article 5.14, Interconnection Customer is responsible for obtaining all permits required by all relevant jurisdictions for the project, including but not limited to, conditional use permits and construction permits; provided however, Transmission Provider shall obtain, at Interconnection Customer's cost and schedule risk, the permits necessary to construct Transmission Provider's facilities that are to be located on real property currently owned or held in fee or right by Transmission Provider.

Subject to applicable provisions in the Agreement and an express written waiver by an authorized officer of Transmission Provider, all of the foregoing permits and real property rights (conferring rights on real property that is environmentally, physically and operationally acceptable to Transmission Provider) shall be acquired as provided herein as a condition to Transmission Provider's contractual obligation to construct or take possession of facilities to be owned by the Transmission Provider under this Agreement. Transmission Provider shall have no liability for any project delays or cost overruns caused by delays in acquiring any of the foregoing permits and/or real property rights, whether such delay results from the failure to obtain such permits or rights or the failure of such permits or rights to meet the requirements set forth herein. Further, any completion dates, if any, set forth herein with regard to Transmission Provider's obligations shall be equitably extended based on the length and impact of any such delays.

With respect to the fiber optic cable on Interconnection Customer's tie line that will be owned by the Transmission Provider, the Interconnection Customer and the Transmission Provider agree that Transmission Provider's ownership and operation of fiber optic cable that is attached to poles or other structures that are owned or maintained by the Interconnection Customer is subject to LGIA Article 5.12, Good Utility Practice, and Transmission Provider's Interconnection Policy 139 (Exhibit 1 to Appendix C to LGIA).

Appendix D To LGIA

Security Arrangements Details

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

Automatic Data Transfer. Throughout the term of this Agreement, Interconnection Customer shall provide the data specified below by automatic data transfer to the Transmission Provider Control Center specified by Transmission Provider or to a Third-Party System Operator designated by Transmission Provider (or both):

From the Interconnection Customer’s collector substation 1:

Analogs:

- o Transformer 1 Real power
- o Transformer 1 Reactive power
- o Transformer 3 Real power
- o Transformer 3 Reactive power
- o Line to collector substation 2 Real power
- o Line to collector substation 2 Reactive power
- o 34.5 kV Reactive power 52F10
- o 34.5 kV Real power 52F11
- o 34.5 kV Reactive power 52F11
- o 34.5 kV Real power 52F12
- o 34.5 kV Reactive power 52F12
- o 34.5 kV Real power 52F31
- o 34.5 kV Reactive power 52F31
- o 34.5 kV Real power 52F32
- o 34.5 kV Reactive power 52F32
- o A phase 230 kV transmission voltage
- o B phase 230 kV transmission voltage
- o C phase 230 kV transmission voltage
- o Average Wind speed

- o Average Plant Atmospheric Pressure (Bar)
- o Average Plant Temperature (Celsius)

Status:

- o 230 kV Transformer Breaker 52T1
- o 230 kV Transformer Breaker 52T3
- o 230 kV Line Breaker 52U
- o 34.5 kV breaker 52F10
- o 34.5 kV breaker 52F11
- o 34.5 kV breaker 52F12
- o 34.5 kV breaker 52F31
- o 34.5 kV breaker 52F32
- o 34.5 kV breaker 52C1
- o 34.5 kV breaker 52C2
- o 34.5 kV breaker 52C3
- o 34.5 kV breaker 52C4

From the Interconnection Customer's collector substation 2:

Analogs:

- o 34.5 kV Real power 52F21
- o 34.5 kV Reactive power 52F21
- o 34.5 kV Real power 52F22
- o 34.5 kV Reactive power 52F22
- o 34.5 kV Real power 52F23
- o 34.5 kV Reactive power 52F23
- o 34.5 kV Real power 52F24
- o 34.5 kV Reactive power 52F24
- o A phase 230 kV transmission voltage
- o B phase 230 kV transmission voltage
- o C phase 230 kV transmission voltage
- o Average Wind speed
- o Average Plant Atmospheric Pressure (Bar)
- o Average Plant Temperature (Celsius)

Status:

- o 230 kV Transformer Breaker 52T2
- o 34.5 kV breaker 52F21
- o 34.5 kV breaker 52F22
- o 34.5 kV breaker 52F23
- o 34.5 kV breaker 52F24

Billing Meter Data. Bi-directional revenue meter at the Point of Interconnection will not be configured to allow direct dial-up access by Interconnection Customer. The Transmission Provider will provide alternatives, at the Interconnection Customer's expense, upon request.

Additional Data. Interconnection Customer shall, at its sole expense, provide any additional Generating Facility data reasonably required and necessary for the Transmission Provider to operate the Transmission System in accordance with Good Utility Practice and Exhibit 1 to Appendix C, Facility Interconnection Requirements for Transmission Systems.

Relay and Control Settings

If Interconnection Customer requires modifications to the settings associated with control/protective devices connected to the distribution and/or transmission system, Interconnection Customer will contact Transmission Provider and provide in writing the justification for the proposed modifications. This will allow Transmission Provider to analyze the modifications and ensure there will be no negative impacts to connected systems and customers.

Appendix E To LGIA

Commercial Operation Date

This Appendix E is a part of the LGIA between Transmission Provider and Interconnection Customer.

[Date]

[Transmission Provider Address]

Re: _______________ Large Generating Facility

Dear _______________:

On **[Date] [Interconnection Customer]** has completed Trial Operation of Unit No. __. This letter confirms that [Interconnection Customer] commenced Commercial Operation of Unit No. ___ at the Large Generating Facility, effective as of **[Date plus one day]**.

Thank you.

[Signature]

[Interconnection Customer Representative]

Appendix F to LGIA

Addresses for Delivery of Notices and Billings

Notices, Billings and Payments:

Transmission Provider:

US Mail Deliveries:	PacifiCorp Transmission Services Attn: Central Cashiers Office PO Box 2757 Portland, OR 97208-2757
Other Deliveries:	Central Cashiers Office Attn: PacifiCorp Transmission Services 825 NE Multnomah Street, Suite 550 Portland OR 97232
Phone Number:	503-813-6774

Interconnection Customer:
Cedar Springs Wind, LLC
Attn: Business Manager, West Area
700 Universe Blvd
Juno Beach, FL 33408

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

Director, Transmission Services	503-813-7237
Manager, Transmission Scheduling	503-813-5342
Director, Interconnection Services	503-813-6496
Transmission Business Facsimile	503-813-6893

OASIS Address:
http://www.oasis.pacificorp.com/oasis/ppw/main.htmlx

Interconnection Customer:
Cedar Springs Wind, LLC
Attn: Bill Narvaez
Senior Transmission Business Manager
Guillermo.Narvaez@nee.com

Appendix G to LGIA

INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating

plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or "GSU"), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the

fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. Power Factor Design Criteria (Reactive Power)

The following reactive power requirements apply only to a newly interconnecting wind generating plant that has executed a Facilities Study Agreement as of the effective

date of the Final Rule establishing the reactive power requirements for non-synchronous generators in section 9.6.1 of this LGIA (Order No. 827). A wind generating plant to which this provision applies shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the high side of the Interconnection Customer’s GSU transformer as defined in this LGIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

Exhibit 1 to Appendix A to LGIA

One-Line Diagram

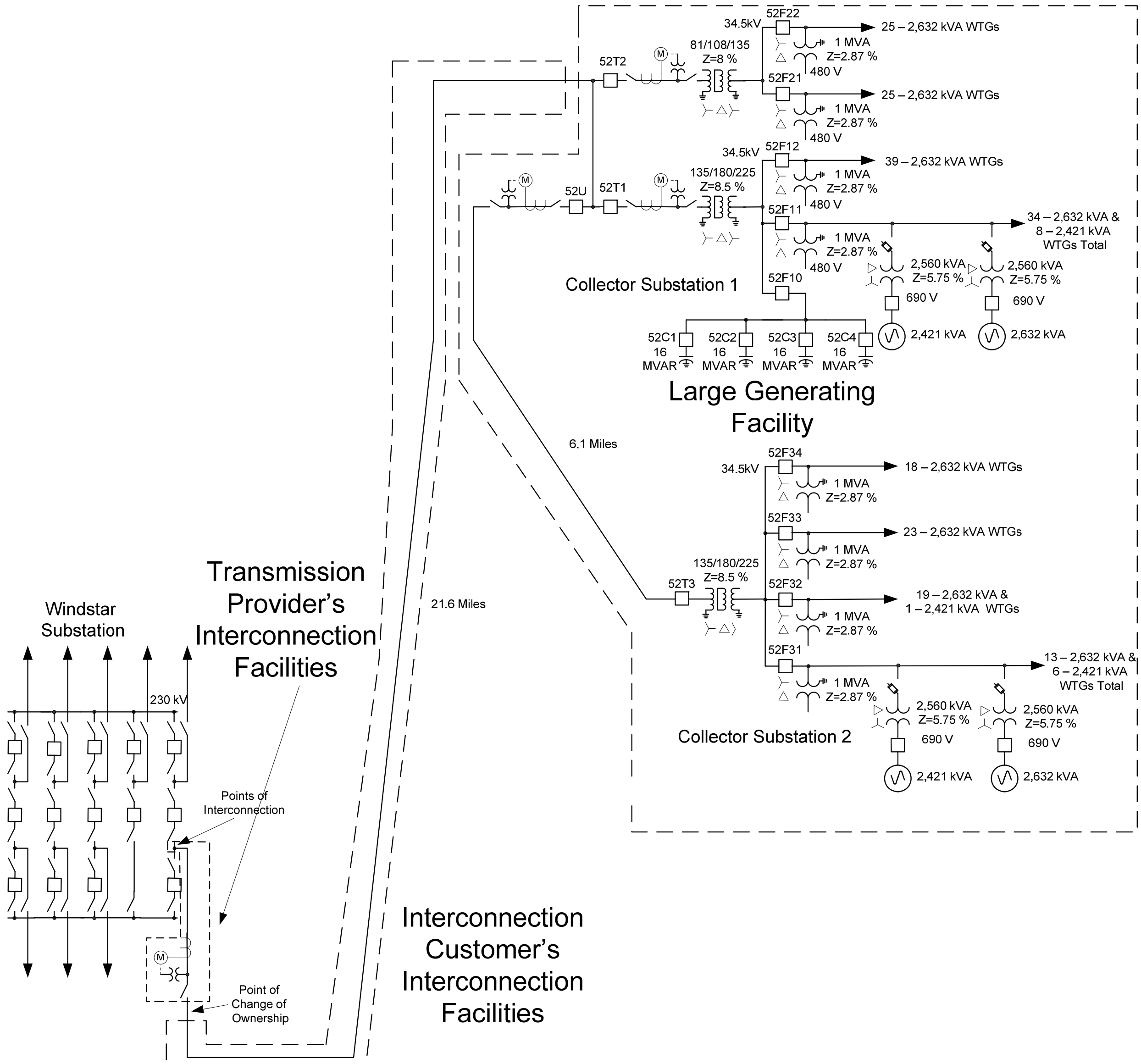

Exhibit 1 to Appendix B to LGIA

Scope of Work

Generating Facility Modifications

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer's Generating Facility.

Interconnection Customer to be Responsible For

- Design the Generating Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer's GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the Generating Facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Generating Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Transmission Provider.
- Install a Phasor Measurement Unit to collect data from the Project. The data must be collected and be able to stream to the Planning Coordinator for each of the Generator Facility's step-up transformers measured on the low side of the GSU at a sample rate of at least 30 samples per second and synchronized within +/- 2 milliseconds of the Coordinated Universal Time (UTC). Initially, the following data must be collected:
  - Three phase voltage and voltage angle (analog)
  - Three phase current (analog)

  Data requirements are subject to change as deemed necessary to comply with local and federal regulations.

- Operate the Generating Facility so as to maintain the voltage at the POI, or other designated point as deemed appropriate by Transmission Provider, at a voltage schedule to be provided by the Transmission Provider following testing. Voltage will typically be required to operate between 1.00 and 1.04 per unit.
- Operate the Generating Facility with a voltage droop.
- Have any Transmission Provider required studies, such as a voltage coordination study, performed and provide results to Transmission Provider. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Ensure the Generating Facility is analyzed for Subsynchronous Resonance ("SSR")/ Subsynchronous Control Interaction ("SSCI") issues, if any are identified based on the Transmission Provider's future long term transmission plans.
- Meet the Federal Energy Regulatory Commission (FERC) and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide the Transmission Provider a standard model from the WECC Approved Dynamic Model Library.
- Establish permanent station retail service with the Transmission Provider's retail business unit for power that will flow from the Transmission Provider's system when the Project is not generating.
- Provide any construction or backup retail service necessary for the Project.
- Prior to Commercial Operation provide the Transmission Provider documentation that the Interconnection Customer has registered as both the Generator Owner ("GO") and Generator Operator ("GOP") of the Generating Facility.

Interconnection Customer Collector Substation 1

- Procure, install, own and maintain a set of line relays that will detect and clear all faults on the tie line between the Interconnection Customer's collector 1 and 2 substations in 5 cycles or less.
- Procure, install, own and maintain a set of line relays that will detect and clear all faults on the tie line between the Interconnection Customer's collector 1 substation and the POI substation in 5 cycles or less. The relay settings are to be

coordinated with and approved by the Transmission Provider.

- Design, procure, and install a Transmission Provider approved data concentrator to capture the required Interconnection Customer device data points and to transfer data from the collector substation to the Transmission Provider's POI substation via an optical fiber communications circuit in DNP3 protocol. The Transmission Provider will input and hold the second level passwords for the data concentrator. Password control ensures the Transmission Provider is aware of and is accepting of the changes being requested by the Interconnection Customer.
- Design, procure and install conduit and control cabling and hard wire the Interconnection Customer's source devices to the data concentrator. Replicated values are not acceptable.
- Provide the following points which are based on the Interconnection Customer's most recent design information. Please note that this list of points could change if the Interconnection Customer's final design changes:

  Analogs:
  - Transformer 1 Real power
  - Transformer 1 Reactive power
  - Transformer 3 Real power
  - Transformer 3 Reactive power
  - Line to collector substation 2 Real power
  - Line to collector substation 2 Reactive power
  - 34.5 kV Reactive power 52F10
  - 34.5 kV Real power 52F11
  - 34.5 kV Reactive power 52F11
  - 34.5 kV Real power 52F12
  - 34.5 kV Reactive power 52F12
  - 34.5 kV Real power 52F31
  - 34.5 kV Reactive power 52F31
  - 34.5 kV Real power 52F32
  - 34.5 kV Reactive power 52F32
  - A phase 230 kV transmission voltage
  - B phase 230 kV transmission voltage
  - C phase 230 kV transmission voltage
  - Average Wind speed
  - Average Plant Atmospheric Pressure (Bar)
  - Average Plant Temperature (Celsius)

  Status:
  - 230 kV Transformer Breaker 52T1

  - o 230 kV Transformer Breaker 52T3
  - o 230 kV Line Breaker 52U
  - o 34.5 kV breaker 52F10
  - o 34.5 kV breaker 52F11
  - o 34.5 kV breaker 52F12
  - o 34.5 kV breaker 52F31
  - o 34.5 kV breaker 52F32
  - o 34.5 kV breaker 52C1
  - o 34.5 kV breaker 52C2
  - o 34.5 kV breaker 52C3
  - o 34.5 kV breaker 52C4
- Provide a separate fenced area within the Interconnection Customer’s collector substation control building for the Transmission Provider’ sole use. The Transmission Provider’s section of the control building shall have a separate door with a Transmission Provider lock. The size of the Transmission Provider’s portion of the control building shall be confirmed during detailed design of the facility. Fencing, gates and road access for the control building shall meet Transmission Provider standards.
- Perform a CDEGS grounding analysis for the control building site and provide the results to the Transmission Provider.
- Coordinate with the Transmission Provider on the Interconnection Customer’s provision of all required SCADA data. This could be achieved by providing the data to the Transmission Provider directly into the POI substation or by the installation of fiber optic cable into and out of the Transmission Provider’s portion of the collector 1 substation control building.
- Procure and install Transmission Provider approved structures for each set of the Transmission Provider’s 230 kV instrument transformers, including all hardware for a complete dead-end assembly to and from the instrument transformers. The installation location of each of the structures shall be coordinated with the Transmission Provider.
- Install all Transmission Provider provided instrument transformers.
- Install complete conduit and the control cable provided by the Transmission Provider from all of the Transmission Provider’s instrument

transformers to the Transmission Provider's portion of the collector substation control building.

- Procure, install, own and maintain instrument transformer disconnect switches on each side of each of all Transmission Provider CT/VT instrument transformers.
- Provide Transmission Provider unfettered and maintained access to all of the Transmission Provider's CT/VT instrument transformers and associated equipment.

Interconnection Customer Collector Substation 2

- Procure, install, own and maintain a set of line relays that will detect and clear all faults on the tie line between the Interconnection Customer's collector A and B substations in 5 cycles or less. The relay settings are to be coordinated with and approved by the Transmission Provider.
- Design, procure, and install a Transmission Provider approved data concentrator to capture the required Interconnection Customer device data points and to transfer data from the collector substation to the Transmission Provider's POI substation via an optical fiber communications circuit in DNP3 protocol. The Transmission Provider will input and hold the second level passwords for the data concentrator. Password control ensures the Transmission Provider is aware of and is accepting of the changes being requested by the Interconnection Customer.
- Design, procure and install conduit and control cabling and hard wire the Interconnection Customer's source devices to the data concentrator. Replicated values are not acceptable.
- Provide the following points which are based on the Interconnection Customer's most recent design information. Please note that this list of points could change if the Interconnection Customer's final design changes:

  Analogs:
  - o 34.5 kV Real power 52F21
  - o 34.5 kV Reactive power 52F21
  - o 34.5 kV Real power 52F22
  - o 34.5 kV Reactive power 52F22
  - o 34.5 kV Real power 52F23
  - o 34.5 kV Reactive power 52F23

  - o 34.5 kV Real power 52F24
  - o 34.5 kV Reactive power 52F24
  - o A phase 230 kV transmission voltage
  - o B phase 230 kV transmission voltage
  - o C phase 230 kV transmission voltage
  - o Average Wind speed
  - o Average Plant Atmospheric Pressure (Bar)
  - o Average Plant Temperature (Celsius)

  Status:
  - o 230 kV Transformer Breaker 52T2
  - o 34.5 kV breaker 52F21
  - o 34.5 kV breaker 52F22
  - o 34.5 kV breaker 52F23
  - o 34.5 kV breaker 52F24
- Procure, install, own and maintain Transmission Provider approved fiber optic cable from the data concentrator to a splice on the tie line running from the collector 2 substation to the collector substation 1.
- Coordinate with the Transmission Provider on the Interconnection Customer's provision of all required SCADA data. This could be achieved by providing the data to the Transmission Provider directly into the POI substation or by the installation of fiber optic cable into and out of the Transmission Provider's portion of the collector 1 substation control building.

Interconnection Customer Collector Substation 1-Collector Substation 2 Tie Line

- Procure all necessary permits, property rights and/or rights of way for the new transmission line between the Interconnection Customer's collector 1 and 2 substations. Interconnection Customer will be responsible for all required regulatory or compliance reporting associated with this transmission line.
- Design, construct, own and maintain the 230 kV transmission tie line between the Interconnection Customer's collector 1 and 2 substations.
- Design, procure, install, own and maintain Transmission Provider standard fiber optic cable on the transmission line.
- Splice the fiber to the fiber running from the data concentrator in the collector 2 substation.

Transmission Provider to be Responsible For

- Provide the Interconnection Customer the designated point at which the voltage is to be maintained and the associated voltage schedule.
- Identify any necessary studies that the Interconnection Customer must have performed or participate in.
- Identify the values to be stored in the PMU.
- Coordinate with the Interconnection Customer on the space requirements for the Transmission Provider’s portion of the Interconnection Customer’s collector 1 substation control building. Provide all fencing, gate and road access standards for the building.
- Procure and install a backup DC battery system for the Transmission Provider portion of the collector substation 1 control building.
- Procure and install a communications rack and associated communications equipment in the Transmission Provider’s portion of the control building and coordinate the termination of any fiber runs to be installed by the Interconnection Customer.
- Procure 230 kV instrument transformers for each of the Interconnection Customer’s collector substation 1 step up transformers. Provide to Interconnection Customer and coordinate the installation.
- Procure 230 kV instrument transformers for the line running from the collector 2 substation. Provide to Interconnection Customer and coordinate the installation.
- Procure all conduit and control cable for all Transmission Provider instrument transformers and provide to Interconnection Customer. Coordinate with the Interconnection Customer on the installation of control cable from the Transmission Provider’s instrument transformers to the control building.
- Design, procure and install 3 sets of 230 kV revenue metering equipment including metering panels, primary and secondary revenue quality meters, test switches, junction boxes, routers and secondary metering wire.
- Establish an Ethernet connection for retail sales and generation accounting via the MV-90 translation system.

Tie Line Requirements

The following outlines the design, procurement, construction, installation, and ownership of equipment associated with the radial line connecting the Interconnection Customer's collector substation 1 to the Transmission Provider's POI substation.

Interconnection Customer to be Responsible For

- Procure all necessary permits, property rights and/or rights of way for the new transmission line between the Interconnection Customer's collector substation 1 and POI substation. Interconnection Customer will be responsible for all required regulatory or compliance reporting associated with the tie line.
- Design, construct, own and maintain the 230 kV transmission tie line between the Interconnection Customer's collector substation 1 and the POI substation.
- Design, procure, install, own and maintain Transmission Provider standard fiber optic cable on the transmission tie line. Provide at least one buffer tube with 12 strands of fiber for the Transmission Provider's sole use.
- Splice the fiber running from the Transmission Provider's portion of the collector substation control building to the Transmission Provider's buffer tube of fiber.
- Construct the final structure outside the POI substation to Transmission Provider's current design and installation standards and in a location approved by the Transmission Provider.
- Provide and install conductor, fiber, shield wire and line hardware in sufficient quantities to allow the Transmission Provider to terminate the tie line into POI substation dead-end structure. The Point of Change of Ownership will be at the last Interconnection Customer structure.

Transmission Provider to be Responsible For

- Provide the Interconnection Customer the necessary specifications for the last structure outside the POI substation.

Point of Interconnection

The following outlines the design, procurement, construction, installation, and ownership of equipment at the POI.

Interconnection Customer to be Responsible For

- Test and commission the communication path between the Interconnection Customer's data concentrators and the POI substation.

Transmission Provider to be Responsible For

- Procure all necessary permits, property rights and/or rights of way to allow for the expansion of Windstar substation.
- Design, procure and construct the necessary infrastructure to expand the substation to create a line position including the installation of the following major equipment:
  - (1) – 230 kV, circuit breaker
  - (3) – 230 kV, combined CT/VT metering unit
  - (1) – 230 kV, group operated switch, breaker disconnect
  - (1) – 230 kV, group operated switch, line disconnect
  - (1) – 230 kV, group operated switch, meter disconnect
  - (3) – 230 kV, surge arrester
  - Deadend structure
  - Ground grid and conduit
- Perform a CDEGS grounding analysis.
- Design, procure and install a line current differential relay system for the connection to the Interconnection Customer's tie line.
- Modify protective relay elements in the line relays in Windstar substation to monitor voltage and frequency of the Interconnection Customer's Generating Facility.
- Install fiber from the substation control building to the Interconnection Customer tie line dead end structure and splice to the fiber provided by the Interconnection Customer.
- Install necessary communications equipment to tie the Interconnection Customer's communications path to the Transmission Provider's communications network.
- Include the following data points into the substation RTU:

  Analogs:
  - Net Generation MW
  - Net Generator MVAr
  - Energy Register

- Observe the Interconnection Customer's test of the communications system running from the collector substations to the POI substation and provide acceptance of functionality.
- Design, procure and install 230 kV revenue metering equipment for the Project including two (2) revenue quality meters, test switch, instrument transformers, metering panels, junction box and secondary metering wire.
- Provide and install an Ethernet connection for retail sales and generation accounting via the MV-90 translation system.

Other

The following outlines the design, procurement, construction, installation, and ownership of equipment past the POI.

TRANSMISSION PROVIDER TO BE RESPONSIBLE FOR

- Aeolus-Shirley Basin #1 Transmission Line
  - Procure any required permits, property rights and/or rights-of-way necessary in order for the line to be rebuilt.
  - Rebuild the approximately 16 miles of the transmission line with double bundled 1158.4 ACSS/TW (Hudson) conductor.
  - Procure and install OPGW fiber optic cable on the rebuilt transmission line in the static wire position.
- Aeolus-Freezeout Transmission Line
  - Procure any required permits, property rights and/or rights-of-way necessary in order for the line to be rebuilt.
  - Rebuild the approximately 3.5 miles of the transmission line with bundled 1158.4 ACSS/TW conductor.
  - Procure and install OPGW fiber optic cable on the rebuilt transmission line in the static wire position.
- Freezeout-Standpipe Transmission Line
  - Procure any required permits, property rights and/or rights-of-way necessary in order for the line to be rebuilt.
  - Rebuild the approximately 11.5 miles of the transmission line with bundled 2-1272 ACSR conductor.
- Freezeout substation

  - o Procure the following major equipment to replace existing equipment in the substation:
    - ▪ 3 – 230 kV, circuit breaker
    - ▪ 8 – 230 kV, group operated switch, breaker disconnect
    - ▪ 2 – 230 kV, group operated switch, line disconnect
  - o Perform a CDEGS grounding analysis.
  - o Develop and implement new relay settings for the rebuilt lines to Aeolus and Standpipe substations.
  - o Install conduit and underground fiber optic cable from splices of the newly installed OPGW running from both Standpipe and Aeolus substations and terminate the underground fiber runs in the substation control building.
  - o Install the necessary communications equipment to terminate the new fiber in the substation control building.
- Aeolus substation
  - o Develop and implement new relay settings for the rebuilt line to Freezeout substation.
  - o Install conduit and underground fiber optic cable from splice of the newly installed OPGW running from both Freezeout substation and terminate the underground fiber in the substation control building.
  - o Install the necessary communications equipment to terminate the new fiber in the substation control building.
- Standpipe substation
  - o Develop and implement new relay settings for the rebuilt line to Freezeout substation.
  - o Install conduit and underground fiber optic cable from splice of the newly installed OPGW running from both Freezeout substation and terminate the underground fiber in the substation control building.
  - o Install the necessary communications equipment to terminate the new fiber in the substation control building.
- Shirley Basin substation
  - o Develop and implement new relay settings for the rebuilt line to Aeolus substation.
- System Operations Control Centers

- o Update databases to include Interconnection Customer and Transmission Provider Interconnection Facilities and Network Upgrades.

Exhibit 1 to Appendix C to LGIA

Facility Connection Requirements for Transmission Systems

PacifiCorp Policy 139

(see attached)

Appendix H
Requirements Applicable to
Multiple Interconnection Customer Signatories

Customer Signatory Requirements

a. The Interconnection Customer's rights and obligations under this Amended and Restated Large Generator Interconnection Agreement ("LGIA") shall be held, subject to the provisions of this Appendix H, jointly by Cedar Springs Wind, LLC, Cedar Springs Transmission LLC, and Cedar Springs Wind III, LLC (each, a "Customer Signatory"), who together comprise the Interconnection Customer under this LGIA. Cedar Springs Wind, LLC, owns the 200 MW Cedar Springs 1 Generating Facility ("Cedar Springs I"), Cedar Springs Transmission LLC, owns the 200 MW Cedar Springs 2 Generating Facility ("Cedar Springs II"), and Cedar Springs Wind III, LLC owns the 120 MW Cedar Springs 3 Generating Facility ("Cedar Springs III").

b. Each Customer Signatory shall be jointly and severally liable for all liabilities and obligations of the Interconnection Customer under this LGIA, including all monetary obligations, which includes the funding of all Interconnection Facilities that are required to be funded by the Interconnection Customer in order to accommodate the interconnection of Cedar Springs I, Cedar Springs II, and Cedar Springs III.

c. There shall be no more than three Customer Signatories comprising the Interconnection Customer, and no Customer Signatory may further subdivide, in any manner or form, its interests in this LGIA or in the Interconnection Customer's Interconnection Facilities without the written consent of the other Customer Signatories and the Transmission Provider. Each of the Customer Signatories acknowledges and agrees that the administrative burden to the Transmission Provider to administer this LGIA would be excessive if any Customer Signatory were to further subdivide its interests in this LGIA or in the Interconnection Customer's Interconnection Facilities in violation of this clause (c) of this Appendix H, and any such action would be considered a Breach and, if not cured pursuant to Article 17 of this LGIA, a Default under Article 17 of this LGIA, entitling the Transmission Provider to terminate this LGIA. The Parties acknowledge that each

Customer Signatory may assign its rights in the Interconnection Customer's Interconnection Facilities and this LGIA for collateral security purposes in accordance with Article 19 of this LGIA.

d. In accordance with Section 19 of the LGIA, no Customer Signatory may assign its interests in the Interconnection Customer's Interconnection Facilities or any of its rights and obligations under this LGIA independently of its interest in Cedar Springs I, Cedar Springs II or Cedar Springs III, as the case may be, and then only with the written consent of the Transmission Provider and the other Customer Signatories. Cedar Springs Transmission LLC has already sought Transmission Provider’s consent to assign its rights and obligations under this LGIA and to Interconnection Customer’s Interconnection Facilities to PacifiCorp’s load-serving entity function (i.e. not the Transmission Provider function that is the signatory to this LGIA), which has entered into an agreement to purchase the Cedar Springs II facility, and Transmission Provider hereby memorializes its consent to said assignment which shall be effective upon the sale of Cedar Springs II facility to PacifiCorp’s load-serving entity function.

e. The Customer Signatories shall appoint a manager to serve as the Interconnection Customer's authorized agent and representative for purposes of administering this LGIA (the “Manager”). Pursuant to the SFA, the Customer Signatories will appoint, upon execution of the SFA, Cedar Springs Wind, LLC as the Manager. The Manager’s contact information is as set forth in Appendix F of this LGIA. In accordance with the terms of the SFA, upon replacement of the Manager under the SFA, any Customer Signatory (other than any Customer Signatory that is the Manager) may change the Manager or Manager’s contact information by delivering written notice of such change to the Transmission Provider not less than five Business Days prior to the effective date of the change in accordance with Notices in Appendix F. The Manager will be a single point of contact for the Transmission Provider and will represent Interconnection Customer for notice purposes and all other communications between the Transmission Provider and Interconnection Customer. All payments, indicia of insurance, and indicia of security to be provided by the Interconnection Customer to the Transmission Provider pursuant to this LGIA shall be provided only by the Manager on behalf of all Customer Signatories; provided, however that nothing herein shall be construed as obligating the Manager to obtain a single insurance policy on behalf of the other Customer Signatories or obtain security on behalf of any other Customer Signatory. Any invoices or refunds due to the Interconnection Customer by the Transmission Provider shall be made only to the Manager on behalf of all Customer Signatories. The Manager shall bear all responsibility for disbursing any refunds and disseminating any invoices, notices, or other communications and for facilitating communications between and among the Customer Signatories with respect to this LGIA, and each Customer Signatory hereby waives any right to individual invoice, notice or communication from the Transmission Provider. The Transmission Provider will not be obligated to act on any notice, instruction, or other communication from a Customer Signatory (except to the extent that such Customer Signatory is acting as the Manager). The Manager's actions and representations to the Transmission Provider shall be binding upon the Interconnection Customer and each Customer Signatory. Each Customer Signatory shall be jointly and severally liable and responsible to Transmission Provider for the Manager's actions taken in connection with this LGIA.

f. It is understood that each of the Customer Signatories will enter into a Shared Facilities Agreement ("SFA") governing, among other things, the liabilities and obligations of the Interconnection Customer and Manager under this LGIA and the rights and responsibilities of each Customer Signatory with respect to the other Customer Signatories. The SFA will establish the rights of the Customer Signatories as tenants-in-common with respect to this LGIA, the Interconnection Customer's Interconnection Facilities and other shared infrastructure. While the SFA will address the Customer Signatories' rights and obligations as between themselves with respect to their co-tenancy rights in this LGIA, the Interconnection Customer's Interconnection Facilities and other shared infrastructure, the Customer Signatories remain jointly and severally liable for compliance with all liabilities and obligations of the Interconnection Customer under this LGIA.

g. The Parties agree that the entire 520 MW net generating capacity comprised of the Cedar Springs I, Cedar Springs II, and Cedar Springs III generating facilities shall be considered to be a single Generating Facility for purposes of this LGIA. Except as otherwise set forth in this Appendix H of this LGIA, each Customer Signatory acknowledges and agrees that the Transmission Provider shall not treat any portion of

Cedar Springs I, Cedar Springs II, and Cedar Springs III as a stand-alone Large Generating Facility or differently from any other portion of the Generating Facility. Moreover, the Customer Signatories shall act as a single entity in exercising the rights and performing the obligations of Interconnection Customer under this LGIA. The Transmission Provider shall treat all Customer Signatories comprising the Interconnection Customer as a single entity under this LGIA and bear no obligation or responsibility to any individual Customer Signatory separately from the Interconnection Customer. Interconnection Customer's obligation to perform its obligations under this LGIA shall not be excused by reason of the Customer Signatories’ failure to agree with respect to any obligation of the Interconnection Customer.

h. Notwithstanding Section 17.1.2 of this LGIA, in the event of a Breach by the Interconnection Customer, Transmission Provider will use best efforts to negotiate a replacement LGIA with one or more Customer Signatories if termination of the LGIA as to all Customer Signatories is not required to address such Breach. If Transmission Provider seeks to terminate this LGIA without such a replacement LGIA, Transmission Provider shall include in its LGIA termination filing with the FERC referenced in Section 2.3.3 of this LGIA an explanation to the FERC as to why a replacement LGIA as to one or more Customer Signatories was not executed.

REDACTED
Docket No. UE 374
Exhibit PAC/818
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

Cedar Springs Rights of Way

February 2020

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

Docket No. UE 374
Exhibit PAC/819
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

Permit Status Record Cedar Springs

February 2020

CPCN/Project Name: Cedar Springs ("CS") I and II Projects
(Cedar Springs I is a nominal 200 MW portion of a nominal 400 MW wind facility and associated infrastructure
(Cedar Springs II is a nominal 200 MW portion of a Nominal 400 MW wind facility and associated infrastructur

Agency	**Required Permit**	**Date Obtained**
Federal Aviation Administration	Notice of Proposed Construction or Alteration	In FAA review; results expected in August 2019
Department of Commerce National Telecommunication Information Agency	Impacts to Telecommunication Systems and Radar	Will be completed by NextEra
U.S. Environmental Protection Agency (EPA)	Spill Prevention Controls and Countermeasure Plan (SPCC)	Will be completed by NextEra
Federal Communication Commission	Licensed Microwave Study	Will be completed by NextEra
WY Department of Environmental Quality	Wyoming Industrial Development Information and Siting Act /Industrial Siting Council Order	28-Jun-2019
WY Department of Environmental Quality	Wyoming Pollutant Discharge Elimination System (WYPDES) - Large Construction General Permit (WYR10-000) - Notice of Intent (NOI) and Storm Water Pollution and Prevention Plan (SWPPP)	Will be completed by NextEra; preparing SWPPP for submittal by August 2, 2019 - Westwood
WY Department of Environmental Quality	Permit to Construct Small Wastewater Facilities (Septic Tanks and Leach fields)	Will be completed by NextEra
WY Department of Environmental Quality	Section 401 Water Quality Certification	Will be completed by NextEra
WY Department of Environmental Quality	Temporary Increase in Turbidity	Will be completed by NextEra
WY State Engineers Office	Permit to appropriate groundwater (use, storage, wells, dewatering) or water stored in impoundments or reservoirs W.S. 41 3-901 through 41-3-938, as amended (Form U.W. 5)	Will be completed by NextEra
WY Department of Transportation	Port of Entry	Will be completed by NextEra
WY Department of Transportation	Right-of-way encroachment	Will be completed by NextEra
WY Department of Transportation	Permit for Oversized / Overweight Loads	Will be completed by NextEra
WY Department of Transportation	Highway Access Permit	Will be completed by NextEra
WY Department of Transportation	Utility/Transmission Line Crossing	Will be completed by NextEra
WY State Historic Preservation Office	Section 106 of Natl Historic Preservation Act of 1966 as amended (16 U.S.C. 470 et seq) and Advisory Council Regulations on the Protection of Historic and Cultural Properties as amended (36 CFR 800)	Will be completed by NextEra
WY Game and Fish Department	WGFD Conservation Plan	Will be completed in August 2019
WY Department of Transportation	Road Use Permit	Road use agreement for transmission tie-line and substation construction will be completed in August 2019; road use agreement for wind park construction will be completed in September 2019
Converse County	Wind Energy Conversion System Use Permit (may be waived in lieu of ISA application and permit)	30-Apr-2019
Converse County	Building permit(s)	Not required
Converse County	Road Use Permit	Will be completed in August 2019

REDACTED
Docket No. UE 374
Exhibit PAC/820
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

Capital Costs Summary Pryor Mountain

February 2020

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Docket No. UE 374
Exhibit PAC/821
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

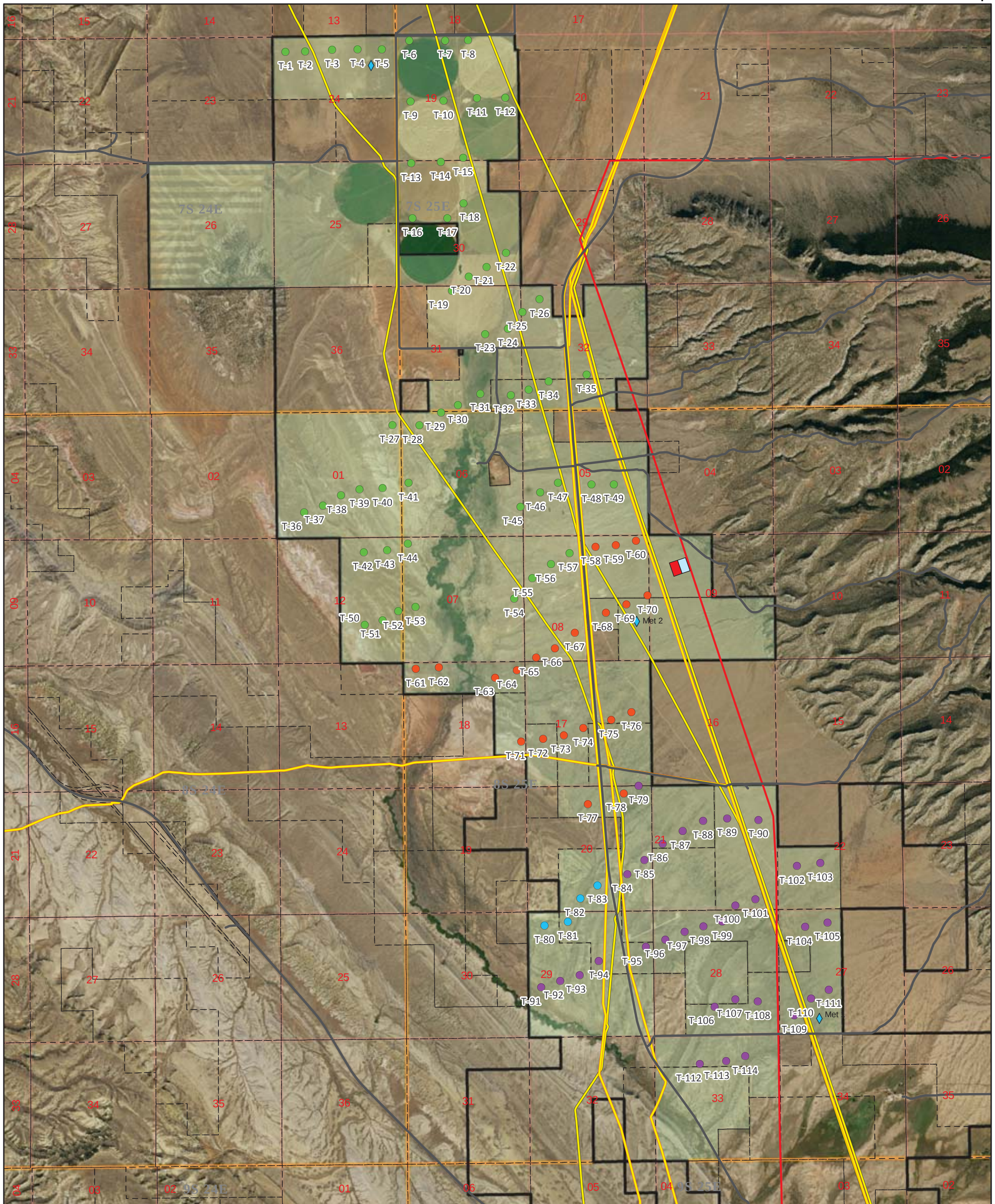
OF OREGON

PACIFICORP

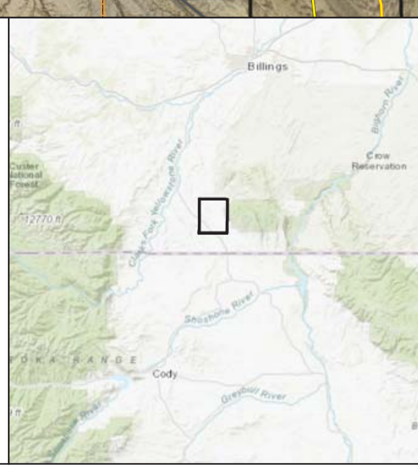
Exhibit Accompanying Direct Testimony of Chad A. Teply

Site Plan Pryor Mountain

February 2020



- V110-2.0MK10B
- V110-2.2MK10C
- V110-2.2MK10D
- GE2.3-116
- Permanent Met Masts
- Collector Substation
- POI Substation
- Public Roads
- Transmission Line
- Natural Gas Pipelines
- Oil Pipelines
- Active Development Area
- 2014 SWPPP Boundary
- Parcel Boundaries



Pryor Mountain Wind Farm

Turbine Layout
Revision 13

Carbon County, Montana
14 November 2019

Preliminary/Subject to Change

N
0 0.25 0.5 1 1.5 Miles
0 0.5 1 2 Kilometers

BLACK & VEATCH

Service Layer Credits: Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community

REDACTED
Docket No. UE 374
Exhibit PAC/822
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

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Exhibit Accompanying Direct Testimony of Chad A. Teply

Wind Potential Assessment Pryor Mountain

February 2020

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REDACTED
Docket No. UE 374
Exhibit PAC/823
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

Project Schedule Pryor Mountain

February 2020

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Docket No. UE 374
Exhibit PAC/824
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

Large Generator Interconnection Agreement Pryor Mountain

February 2020

STANDARD LARGE GENERATOR

INTERCONNECTION AGREEMENT (LGIA)
between
PACIFICORP, on behalf of its Transmission Function
and
PACIFICORP, on behalf of its Marketing Function
PRYOR MOUNTAIN

TABLE OF CONTENTS

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this 12th day of September, 2019 by and between PacifiCorp, on behalf of its Marketing function, a corporation organized and existing under the laws of the State of Oregon ("Interconnection Customer" with a Large Generating Facility), and PacifiCorp, on behalf of its Transmission Function a corporation organized and existing under the laws of the State of Oregon ("Transmission Provider and/or Transmission Owner"). Interconnection Customer and Transmission Provider each may be referred to as a "Party" or collectively as the "Parties."

Recitals

WHEREAS, Transmission Provider operates the Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and,

WHEREAS, Interconnection Customer and Transmission Provider have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility with the Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (Tariff).

Article 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection System Impact Study.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or

Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the

Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission

Provider's Transmission System. The scope of the study is defined in Section 43 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System, the scope of which is described in Section 41 of the Standard Large Generator Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility

pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

NERC shall mean the North American Electric Reliability Council or its successor organization.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Provisional Interconnection Service shall mean Interconnection Service provided by Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to Transmission Provider's Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Provisional Large Generator Interconnection Agreement and, if applicable, the Tariff.

Provisional Large Generator Interconnection Agreement shall mean the interconnection agreement for Provisional Interconnection Service established between Transmission Provider and/or the Transmission Owner and the Interconnection Customer. This agreement shall take the form of the Large Generator Interconnection Agreement, modified for provisional purposes.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose.

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that are not part of an Affected System that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Stand Alone Network Upgrade within 15 days of its determination.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in the Transmission Provider's Tariff.

Surplus Interconnection Service shall mean any unneeded portion of Interconnection Service established in a Large Generator Interconnection Agreement, such that if Surplus Interconnection Service is utilized the total amount of Interconnection Service at the Point of Interconnection would remain the same.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission Provider's Transmission System or on other delivery systems or other generating systems to which the Transmission Provider's Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Large Generator Interconnection Agreement to the extent necessary.

Transmission Provider shall mean the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Variable Energy Resource shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Article 2. Effective Date, Term, and Termination

2.1 Effective Date. This LGIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this LGIA with FERC upon execution in accordance with Article 3.1, if required.

2.2 Term of Agreement. Subject to the provisions of Article 2.3, this LGIA shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as Interconnection Customer may request (Term to be specified in individual agreements) and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures.

2.3.1 Written Notice. This LGIA may be terminated by Interconnection Customer after giving Transmission Provider ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

2.3.2 Default. Either Party may terminate this LGIA in accordance with Article 17.

2.3.3 Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this LGIA, which notice has been accepted for filing by FERC.

2.4 Termination Costs. If a Party elects to terminate this Agreement pursuant to Article 2.3 above, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party, as of the date of the other Party's receipt of such notice of termination, that are the responsibility of the Terminating Party under this LGIA. In the event of termination by a Party, the Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this LGIA, unless otherwise ordered or approved by FERC:

2.4.1 With respect to any portion of Transmission Provider's Interconnection Facilities that have not yet been constructed or installed, Transmission Provider shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Provider shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Provider for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Provider shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Provider to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this LGIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which Transmission Provider has incurred expenses and has not been reimbursed by Interconnection Customer.

2.4.2 Transmission Provider may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Provider shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this LGIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 Disconnection. Upon termination of this LGIA, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 Survival. This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this LGIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

Article 3. Regulatory Filings

3.1 Filing. Transmission Provider shall file this LGIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this LGIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission

Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

Article 4. Scope of Service

4.1 **Interconnection Product Options.** Interconnection Customer has selected the following (checked) type of Interconnection Service:

X 4.1.1 **Energy Resource Interconnection Service.**

4.1.1.1 **The Product.** Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interconnection Service, Transmission Provider shall construct facilities identified in Appendix A.

4.1.1.2 **Transmission Delivery Service Implications.** Under Energy Resource Interconnection Service, Interconnection Customer will be eligible to inject power from the Large Generating Facility into and deliver power across the interconnecting Transmission Provider's Transmission System on an "as available" basis up to the amount of MWs identified in the applicable stability and steady state studies to the extent the upgrades initially required to qualify for Energy Resource Interconnection Service have been constructed. Where eligible to do so (e.g., PJM, ISO-NE, NYISO), Interconnection Customer may place a bid to sell into the market up to the maximum identified Large Generating Facility output, subject to any conditions specified in the interconnection service approval, and the Large Generating Facility will be dispatched to the extent Interconnection Customer's bid clears. In all other instances, no transmission delivery service from the Large Generating Facility is assured, but Interconnection Customer may obtain Point-to-Point Transmission Service, Network Integration Transmission Service, or be used for secondary network transmission service, pursuant to Transmission Provider's Tariff, up to the maximum output identified in the stability and steady state studies. In those instances, in order for Interconnection Customer to obtain the right to deliver or inject energy beyond the Large Generating Facility Point of Interconnection or to improve its ability to do so, transmission delivery service must be obtained pursuant to the provisions of Transmission Provider's Tariff. The Interconnection Customer's ability to inject its Large Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of Transmission Provider's Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of firm Point-to-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

☐ **4.1.2 Network Resource Interconnection Service.**

4.1.2.1 The Product. Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as all Network Resources. To the extent Interconnection Customer wants to receive Network Resource Interconnection Service, Transmission Provider shall construct the facilities identified in Appendix A to this LGIA.

4.1.2.2 Transmission Delivery Service Implications. Network Resource Interconnection Service allows Interconnection Customer's Large Generating Facility to be designated by any Network Customer under the Tariff on Transmission Provider's Transmission System as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission

Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Large Generating Facility in the same manner as it accesses Network Resources. A Large Generating Facility receiving Network Resource Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Large Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Large Generating Facility has not been designated as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or firm Point-to-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Large Generating Facility to any particular load on Transmission Provider's Transmission System without incurring congestion costs. In the event of transmission constraints on Transmission Provider's Transmission System, Interconnection Customer's Large Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that Interconnection Customer's Large Generating Facility be designated as a Network Resource by a Network Service Customer under the Tariff or that Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does designate the Large Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interconnection Service, any future transmission service request for delivery from the Large Generating Facility within Transmission Provider's Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Large Generating Facility be undertaken, regardless of whether or not such Large Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Large Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Large Generating Facility outside Transmission Provider's Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

4.2 Provision of Service. Transmission Provider shall provide Interconnection Service for the Large Generating Facility at the Point of Interconnection.

4.3 Performance Standards. Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is a Transmission Provider or Transmission Owner, then that Party shall amend the LGIA and submit the amendment to FERC for approval.

4.4 No Transmission Delivery Service. The execution of this LGIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

4.5 Interconnection Customer Provided Services. The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.5.1.

Interconnection Customer shall be paid for such services in accordance with Article 11.6.

Article 5. Interconnection Facilities Engineering, Procurement, and Construction

5.1 Options. Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either the Standard Option or Alternate Option set forth below, and such dates and selected option shall be set forth in Appendix B, Milestones. At the same time, Interconnection Customer shall indicate whether it elects to exercise the Option to Build set forth in Article 5.1.3 below. If the dates designated by Interconnection Customer are not acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days. Upon receipt of the notification that Interconnection Customer’s designated dates are not acceptable to Transmission Provider, the

Interconnection Customer shall notify Transmission Provider within thirty (30) Calendar Days whether it elects to exercise the Option to Build if it has not already elected to exercise the Option to Build.

5.1.1 **Standard Option.** Transmission Provider shall design, procure, and construct Transmission Provider's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Provider shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Provider reasonably expects that it will not be able to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the specified dates, Transmission Provider shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 **Alternate Option.** If the dates designated by Interconnection Customer are acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities by the designated dates.

If Transmission Provider subsequently fails to complete Transmission Provider's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial

Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B, Milestones; Transmission Provider shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable RTO or ISO refuses to grant clearances to install equipment.

5.1.3 **Option to Build.** Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. Transmission Provider and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 **Negotiated Option.** If the dates designated by interconnection Customer are not acceptable to Transmission Provider the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives, or the procurement and construction of all facilities other than Transmission Provider’s Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects to exercise the Option to Build under Article 5.1.3). If the Parties are unable to reach agreement on such terms and conditions, then, pursuant to Article 5.1.1 (Standard Option), Transmission Provider shall assume responsibility for the design, procurement and construction of all facilities other than Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects to exercise the Option to Build.

5.2 General Conditions Applicable to Option to Build. If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Provider;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Provider shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider;

(5) at any time during construction, Transmission Provider shall have the right to gain unrestricted access to Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Provider, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider for claims arising from Interconnection Customer's construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) Interconnection Customer shall transfer control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Provider's

Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Provider;

(10) Transmission Provider shall approve and accept for operation and maintenance Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information, and any other documents that are reasonably required by Transmission Provider to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

(12) If Interconnection Customer exercises the Option to Build pursuant to Article 5.1.3, Interconnection Customer shall pay Transmission Provider the agreed upon amount of [$PLACEHOLDER] for Transmission Provider to execute the responsibilities enumerated to Transmission Provider under Article 5.2. Transmission Provider shall invoice Interconnection Customer for this total amount to be divided on a monthly basis pursuant to Article 12.

5.3 Liquidated Damages. The actual damages to Interconnection Customer, in the event Transmission Provider's Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Provider pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Provider to Interconnection Customer in the event that Transmission Provider does not complete any portion of Transmission Provider's

Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades, in the aggregate, for which Transmission Provider has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades for which Transmission Provider has assumed responsibility to design, procure, and construct. The foregoing payments will be made by Transmission Provider to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Transmission Provider's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for the Large Generating Facility's Trial Operation or to export power from the Large Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for Large Generating Facility's Trial Operation or to export power from the Large Generating Facility, but for Transmission Provider's delay; (2) Transmission Provider's failure to meet the specified dates is the result of the action or inaction of Interconnection Customer or any other Interconnection Customer who has entered into an LGIA with Transmission Provider or any cause beyond Transmission Provider's reasonable control or reasonable ability to cure; (3) the interconnection Customer has assumed responsibility for the design, procurement and construction of Transmission Provider's

Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 **Power System Stabilizers.** The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative. The requirements of this paragraph shall not apply to wind generators.

5.5 **Equipment Procurement.** If responsibility for construction of Transmission Provider's Interconnection Facilities or Network Upgrades is to be borne by Transmission Provider, then Transmission Provider shall commence design of Transmission Provider's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 Transmission Provider has completed the Facilities Study pursuant to the Facilities Study Agreement;

5.5.2 Transmission Provider has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.5.3 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.6 Construction Commencement. Transmission Provider shall commence construction of Transmission Provider's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Provider's Interconnection Facilities and Network Upgrades;

5.6.3 Transmission Provider has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.6.4 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.7 Work Progress. The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Either Party may, at any time, request a progress report from the other Party. If, at any time, Interconnection Customer determines that the completion of Transmission Provider's Interconnection Facilities will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider of such later date upon which the completion of Transmission Provider's Interconnection Facilities will be required.

5.8 Information Exchange. As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection

Facilities with Transmission Provider's Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 Other Interconnection Options.

5.9.1 **Limited Operation.** If any of Transmission Provider's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Large Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Large Generating Facility and Interconnection Customer's Interconnection Facilities may operate prior to the completion of Transmission Provider's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. Transmission Provider shall permit Interconnection Customer to operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.9.2 **Provisional Interconnection Service.** Upon the request of Interconnection Customer, and prior to completion of requisite Interconnection Facilities, Network Upgrades, Distribution Upgrades, or System Protection Facilities Transmission Provider may execute a Provisional Large Generator Interconnection Agreement or Interconnection Customer may request the filing of an unexecuted Provisional Large Generator Interconnection Agreement with the Interconnection Customer for limited Interconnection Service at the discretion of Transmission Provider based upon an evaluation that will consider the results of available studies. Transmission

Provider shall determine, through available studies or additional studies as necessary, whether stability, short circuit, thermal, and/or voltage issues would arise if Interconnection Customer interconnects without modifications to the Generating Facility or Transmission System. Transmission Provider shall determine whether any Interconnection Facilities, Network Upgrades, Distribution Upgrades, or System Protection Facilities that are necessary to meet the requirements of NERC, or any applicable Regional Entity for the interconnection of a new, modified and/or expanded Generating Facility are in place prior to the commencement of Interconnection Service from the Generating Facility. Where available studies indicate that such, Interconnection Facilities, Network Upgrades, Distribution Upgrades, and/or System Protection Facilities that are required for the interconnection of a new, modified and/or expanded Generating Facility are not currently in place, Transmission Provider will perform a study, at the Interconnection Customer's expense, to confirm the facilities that are required for Provisional Interconnection Service. The maximum permissible output of the Generating Facility in the Provisional Large Generator Interconnection Agreement shall be studied and updated as system conditions warrant (in the determination of the Transmission Provider in its discretion) but no less frequently than annually. Interconnection Customer assumes all risk and liabilities with respect to changes between the Provisional Large Generator Interconnection Agreement and the Large Generator Interconnection Agreement, including changes in output limits and Interconnection Facilities, Network Upgrades, Distribution Upgrades, and/or System Protection Facilities cost responsibilities.

5.10 **Interconnection Customer's Interconnection Facilities ('ICIF').** Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.10.1 **Interconnection Customer's Interconnection Facility Specifications.** Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Provider at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Provider shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 **Transmission Provider's Review.** Transmission Provider's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Provider, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider.

5.10.3 **ICIF Construction.** The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Large Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Large Generating Facility. The Interconnection Customer shall provide Transmission Provider specifications for the excitation system, automatic voltage regulator, Large Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.11 **Transmission Provider's Interconnection Facilities Construction.** Transmission Provider's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Provider shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Provider's Interconnection Facilities [include appropriate drawings and relay diagrams].

Transmission Provider will obtain control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

5.12 Access Rights. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to the other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the Transmission System; (ii) operate and maintain the Large Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners. If any part of Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Provider or Transmission Owner, Transmission Provider or Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Provider or Transmission Owner's

Interconnection Facilities and/or Network Upgrades upon such property.

5.14 Permits. Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities. Interconnection Customer may request Transmission Provider to construct, and Transmission Provider shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 Suspension. Interconnection Customer reserves the right, upon written notice to Transmission Provider, to suspend
at any time all work by Transmission Provider associated with the construction and installation of Transmission Provider's Interconnection Facilities and/or Network Upgrades required under this LGIA with the condition that Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Provider's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Provider (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of

persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Provider cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Provider shall obtain Interconnection Customer's authorization to do so.

Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Transmission Provider required under this LGIA pursuant to this Article 5.16, and has not requested Transmission Provider to recommence the work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Transmission Provider, if no effective date is specified.

5.17 Taxes.

5.17.1 Interconnection Customer Payments Not Taxable. The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Provider for the installation of Transmission Provider's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 Representations and Covenants. In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to Transmission Provider for Transmission Provider's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of Transmission Provider's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Transmission Provider's request, Interconnection Customer shall provide Transmission Provider with a report from an independent engineer confirming its representation in clause (iii), above. Transmission Provider represents and covenants that the cost of Transmission Provider's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon the Transmission Provider. Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless

Transmission Provider from the cost consequences of any current tax liability imposed against Transmission Provider as the result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Transmission Provider.

Transmission Provider shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this LGIA unless (i) Transmission Provider has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Transmission Provider should be reported as income subject to taxation or (ii) any Governmental Authority directs Transmission Provider to report payments or property as income subject to taxation; provided, however, that Transmission Provider may require Interconnection Customer to provide security for Interconnection Facilities, in a form reasonably acceptable to Transmission Provider (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Transmission Provider for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Transmission Provider of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by Transmission

Provider upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 **Tax Gross-Up Amount.** Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Interconnection Customer will pay Transmission Provider, in addition to the amount paid for the Interconnection Facilities and Network Upgrades, an amount equal to (1) the current taxes imposed on Transmission Provider ("Current Taxes") on the excess of (a) the gross income realized by Transmission Provider as a result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit Transmission Provider to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Transmission Provider's composite federal and state tax rates at the time the payments or property transfers are received and Transmission Provider will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value

Depreciation Amount shall be computed by discounting Transmission Provider's anticipated tax depreciation deductions as a result of such payments or property transfers by Transmission Provider's current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.17.5 **Private Letter Ruling or Change or Clarification of Law.** At Interconnection Customer's request and expense, Transmission Provider shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Transmission Provider under this LGIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Transmission Provider and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Transmission Provider shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Transmission Provider shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 **Subsequent Taxable Events.** If, within 10 years from the date on which the relevant Transmission Provider's Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this LGIA terminates and Transmission Provider retains ownership of the Interconnection Facilities and Network Upgrades, Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Transmission Provider, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 **Contests.** In the event any Governmental Authority determines that Transmission Provider's receipt of payments or property constitutes income that is subject to taxation, Transmission Provider shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Transmission Provider may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Transmission Provider reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Transmission Provider shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Transmission Provider may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Transmission Provider, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve

Interconnection Customer from any obligation to indemnify Transmission Provider for the tax at issue in the contest.

5.17.8 **Refund.** In the event that (a) a private letter ruling is issued to Transmission Provider which holds that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Transmission Provider in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not taxable to Transmission Provider, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Transmission Provider are not subject to federal income tax, or (d) if Transmission Provider receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Transmission Provider pursuant to this LGIA, Transmission Provider shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by Interconnection Customer to Transmission Provider for such taxes which Transmission Provider did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Transmission Provider refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Transmission Provider, any refund or credit Transmission Provider receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to Transmission Provider for such overpayment of taxes (including any reduction in interest otherwise payable by Transmission Provider to any Governmental Authority resulting from an offset or credit); provided, however, that Transmission Provider will remit such amount promptly to Interconnection Customer only after and to the extent that Transmission Provider has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to Transmission Provider's Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 **Taxes Other Than Income Taxes.** Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Provider for which Interconnection Customer may be required to reimburse Transmission Provider under the terms of this LGIA. Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Transmission Provider shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Transmission Provider for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Provider.

5.17.10 **Transmission Owners Who Are Not Transmission Providers.** If Transmission Provider is not the same entity as the Transmission Owner, then (i) all references in this Article 5.17 to Transmission Provider shall be deemed also to refer to and to include the Transmission Owner, as appropriate, and (ii) this LGIA shall not become effective until such Transmission Owner shall have agreed in writing to assume all of the duties and obligations of Transmission Provider under this Article 5.17 of this LGIA.

5.18 Tax Status. Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this LGIA is intended to adversely affect any Transmission Provider's tax exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General. Either Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, that Party shall provide to the other Party sufficient information regarding such modification so that the other Party may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Large Generating Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Provider shall provide, within thirty (30) Calendar Days (or such other time as the

Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Provider's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 **Standards.** Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 **Modification Costs.** Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Provider makes to Transmission Provider's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Provider's Interconnection Facilities or the Transmission System, or to provide transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

Article 6. Testing and Inspection

6.1 **Pre-Commercial Operation Date Testing and Modifications.** Prior to the Commercial Operation Date, Transmission Provider shall test Transmission Provider's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the

Large Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Large Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications. Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Large Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 Right to Observe Testing. Each Party shall notify the other Party in advance of its performance of tests of its Interconnection Facilities. The other Party has the right, at its own expense, to observe such testing.

6.4 Right to Inspect. Each Party shall have the right, but shall have no obligation to: (i) observe the other Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of the other Party's System Protection Facilities and other protective equipment; and (iii) review the other Party's maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. A Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Party. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection

Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this LGIA.

Article 7. Metering

7.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Provider shall install Metering Equipment at the Point of Interconnection prior to any operation of the Large Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Large Generating Facility shall be measured at or, at Transmission Provider's option, compensated to, the Point of Interconnection. Transmission Provider shall provide metering quantities, in analog and/or digital form, to Interconnection Customer upon request. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 **Check Meters.** Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Provider's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Provider or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 **Standards.** Transmission Provider shall install, calibrate, and test revenue quality Metering

Equipment in accordance with applicable ANSI standards.

7.4 **Testing of Metering Equipment.** Transmission Provider shall inspect and test all Transmission Provider-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Transmission Provider shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than every two (2) years. Transmission Provider shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Provider's failure to maintain, then Transmission Provider shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission Provider shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

7.5 **Metering Data.** At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Provider and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Large Generating Facility to the Point of Interconnection.

Article 8. Communications

8.1 Interconnection Customer Obligations. Interconnection Customer shall maintain satisfactory operating communications with Transmission Provider's Transmission System dispatcher or representative designated by Transmission Provider. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Large Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Provider as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Large Generating Facility to the location(s) specified by Transmission Provider. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 Remote Terminal Unit. Prior to the Initial Synchronization Date of the Large Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Provider at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Provider through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Provider. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Provider.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 **No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4 **Provision of Data from a Variable Energy Resource.** The Interconnection Customer whose Generating Facility is a Variable Energy Resource shall provide meteorological and forced outage data to the Transmission Provider to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The Interconnection Customer with a Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, wind speed, wind direction, and atmospheric pressure. The Interconnection Customer with a Variable Energy Resource having solar as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission Provider and Interconnection Customer whose Generating Facility is a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility is a Variable Energy Resource also shall submit data to the Transmission Provider regarding all forced outages to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Such requirements for meteorological and forced outage data are set forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

Article 9. Operations

9.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 **Control Area Notification.** At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider in writing of the Control Area in which the Large Generating Facility will be located. If Interconnection Customer elects to locate the Large Generating Facility in a Control Area other than the Control Area in which the Large Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Control Area.

9.3 **Transmission Provider Obligations.** Transmission Provider shall cause the Transmission System and Transmission Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA.

Transmission Provider may provide operating instructions to Interconnection Customer consistent with this LGIA and Transmission Provider's operating protocols and procedures as they may change from time to time. Transmission Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations. Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA. Interconnection Customer shall operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this LGIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Either Party may request that the other Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this LGIA.

9.5 Start-Up and Synchronization. Consistent with the Parties' mutually acceptable procedures, Interconnection Customer is responsible for the proper synchronization of the Large Generating Facility to Transmission Provider's Transmission System.

9.6 Reactive Power and Primary Frequency Response.

9.6.1 Power Factor Design Criteria. Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis. The requirements of this paragraph shall not apply to wind generators.

9.6.1.1 **Synchronous Generation.** Interconnection Customer shall design the Large Generating Facility to maintain a composite power deliver at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all synchronous generators in the Control Area on a comparable basis.

9.6.1.2 **Non-Synchronous Generation.** Interconnection Customer shall design the Large Generating Facility to maintain composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all non-synchronous generators in the Control Area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of the Final Rule establishing this requirement (Order No. 827).

9.6.2 **Voltage Schedules.** Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Transmission Provider shall require Interconnection Customer to operate the Large Generating Facility to produce or absorb reactive power within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Provider's voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. Transmission Provider shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance, and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Large Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the System Operator.

9.6.2.1 **Voltage Regulators.** Whenever the Large Generating Facility is operated in parallel with the Transmission System and voltage regulators are capable of operation, Interconnection Customer shall operate the Large Generating Facility with its voltage regulators in automatic operation. If the Large Generating Facility's voltage regulators are not capable of such automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative, and ensure that such Large Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Large Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Control Area on a comparable basis.

9.6.3 Payment for Reactive Power. Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Large Generating Facility when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1, provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed.

9.6.4 Primary Frequency Response. Interconnection Customer shall ensure the primary frequency response capability of its Large Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term “functioning governor or equivalent controls” as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Large Generating Facility’s real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Large Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Large Generating Facility’s real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Large Generating Facility’s real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Large Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Interconnection Customer shall operate the Large Generating Facility consistent with the provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Large Generating Facilities.

9.6.4.1 Governor or Equivalent Controls. Whenever the Large Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Large Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Large Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Large Generating Facility's governor or equivalent controls to a minimum whenever the Large Generating Facility is operated in parallel with the Transmission System.

9.6.4.2 **Timely and Sustained Response.** Interconnection Customer shall ensure that the Large Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Large Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Large Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

9.6.4.3 **Exemptions.** Large Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement. Large Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 9.6.4, but shall be otherwise exempt from the operating requirements in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.4 of this Agreement.

9.6.4.4 Electric Storage Resources. Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Appendix C of its LGIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.3 of this Agreement. Appendix C shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Appendix C must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 9.6.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination. Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to the Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Party of such removal.

9.7.1.2 Outage Schedules. Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Large Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

9.7.1.3 **Outage Restoration.** If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects the other Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Party, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

9.7.2 **Interruption of Service.** If required by Good Utility Practice to do so, Transmission Provider may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Provider;

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Large Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 **Under-Frequency and Over Frequency Conditions.** The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the Applicable

Reliability Council to ensure "ride through" capability of the Transmission System. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

9.7.4 System Protection and Other Control Requirements.

9.7.4.1 System Protection Facilities. Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Provider's Interconnection Facilities or the Transmission System as a result of the interconnection of the Large Generating Facility and Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

9.7.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 **Requirements for Protection.** In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Provider's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Large Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Large Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Large Generating Facility.

9.7.6 **Power Quality.** Neither Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

9.8 **Switching and Tagging Rules.** Each Party shall provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in

obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Provider's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or Transmission Provider's Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

Article 10. Maintenance

10.1 Transmission Provider Obligations. Transmission Provider shall maintain the Transmission System and Transmission Provider's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.2 Interconnection Customer Obligations. Interconnection Customer shall maintain the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.3 Coordination. The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Large Generating Facility and the Interconnection Facilities.

10.4 Secondary Systems. Each Party shall cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Party. Each Party shall provide advance notice to the other Party before undertaking any work on such circuits, especially on electrical circuits involving circuit

breaker trip and close contacts, current transformers, or potential transformers.

10.5 **Operating and Maintenance Expenses.** Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Provider's Interconnection Facilities.

Article 11. Performance Obligation

11.1 **Interconnection Customer Interconnection Facilities.** Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

11.2 **Transmission Provider's Interconnection Facilities.** Transmission Provider or Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Provider's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

11.3 **Network Upgrades and Distribution Upgrades.** Transmission Provider or Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades. The Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless Transmission Provider or Transmission Owner elects to fund the capital for the Network Upgrades, they shall

be solely funded by Interconnection Customer. In the event that Transmission Provider must change the voltage levels of a discrete portion of the Transmission System to which the Interconnection Customer is connected, Transmission Provider shall give reasonable notice of such change and the Interconnection Customer shall be solely responsible for all costs related to upgrades or modifications to Interconnection Customer's Interconnection Facilities resulting from Transmission Provider's increase in the voltage levels of the Transmission System, in order to remain interconnected with the Transmission System at the new operating voltage. To the extent that the modifications necessary to upgrade Interconnection Facilities qualify as Network Upgrades, Transmission Provider shall be solely responsible for the expense of such modifications or upgrades.

11.4 Transmission Credits.

11.4.1 Repayment of Amounts Advanced for Network Upgrades. Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to Transmission Provider and Affected System Operator, if any, for the Network Upgrades, including any tax gross-up or other tax-related payments associated with Network Upgrades, and not refunded to Interconnection Customer pursuant to Article 5.17.8 or otherwise, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Large Generating Facility. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC=s regulations at 18 C.F.R. § 35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph.

Interconnection Customer may assign such repayment rights to any person.

Notwithstanding the foregoing, Interconnection Customer, Transmission Provider, and Affected System Operator may adopt any alternative payment schedule that is mutually agreeable so long as Transmission Provider and Affected System Operator take one of the following actions no later than five years from the Commercial Operation Date: (1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or (2) declare in writing that Transmission Provider or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full reimbursement shall not extend beyond twenty (20) years from the Commercial Operation Date.

If the Large Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, Transmission Provider and Affected System Operator shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the Generating Facility, if different, is responsible for identifying the entity to which reimbursement must be made.

11.4.2 **Special Provisions for Affected Systems.** Unless Transmission Provider provides, under the LGIA, for the repayment of

amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

11.4.3 Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Large Generating Facility.

11.5 Provision of Security. At least thirty (30) Calendar Days prior to the commencement of the first of the following to occur: design, procurement, installation, or construction of a discrete portion of a Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and shall be

reduced on a dollar-for-dollar basis for payments made to Transmission Provider for these purposes.

In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must indicate that it would only expire upon final payment made to Transmission Provider to cover all relevant costs for designing, procuring, installing, and constructing the applicable portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which the letter of credit was provided.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must indicate that it would only expire upon final payment made to Transmission Provider to cover all relevant costs for designing, procuring, installing, and constructing the applicable portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which the surety bond was provided.

11.6 Interconnection Customer Compensation. If Transmission Provider requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this LGIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to an RTO or ISO FERC-approved rate schedule. Interconnection Customer

shall serve Transmission Provider or RTO or ISO with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this LGIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

11.6.1 Interconnection Customer Compensation for Actions During Emergency Condition. Transmission Provider or RTO or ISO shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.6.

Article 12. Invoice

12.1 General. Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this LGIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice. Within six months after completion of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades, Transmission Provider shall provide an invoice of the final cost of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades and shall set forth such costs in sufficient

detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this LGIA.

12.4 Disputes. In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide Interconnection Service under this LGIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii).

Article 13. Emergencies

13.1 Definition. "Emergency Condition" shall mean a condition or situation: (i) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (ii) that, in the case

of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, Transmission Provider's Interconnection Facilities or the Transmission Systems of others to which the Transmission System is directly connected; or (iii) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Large Generating Facility or Interconnection Customer's Interconnection Facilities' System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by this LGIA to possess black start capability.

13.2 Obligations. Each Party shall comply with the Emergency Condition procedures of the applicable ISO/RTO, NERC, the Applicable Reliability Council, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

13.3 Notice. Transmission Provider shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Provider's Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Transmission Provider promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Provider's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Provider's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall

be followed as soon as practicable with written notice.

13.4 Immediate Action. Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Provider, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or otherwise regarding the Transmission System.

13.5 Transmission Provider Authority.

13.5.1 General. Transmission Provider may take whatever actions or inactions with regard to the Transmission System or Transmission Provider's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Provider's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a

reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Large Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 **Reduction and Disconnection.** Transmission Provider may reduce Interconnection Service or disconnect the Large Generating Facility or Interconnection Customer's Interconnection Facilities, when such, reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of Transmission Provider pursuant to Transmission Provider's Tariff. When Transmission Provider can schedule the reduction or disconnection in advance, Transmission Provider shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection Customer and Transmission Provider. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities, and the Transmission System to their normal

operating state as soon as practicable consistent with Good Utility Practice.

13.6 **Interconnection Customer Authority.** Consistent with Good Utility Practice and the LGIA and the LGIP, Interconnection Customer may take actions or inactions with regard to the Large Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Provider's Interconnection Facilities. Transmission Provider shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.7 **Limited Liability.** Except as otherwise provided in Article 11.6.1 of this LGIA, neither Party shall be liable to the other for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

Article 14. Regulatory Requirements and Governing Law

14.1 **Regulatory Requirements.** Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this LGIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act, the Public Utility Holding Company

Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

Article 15. Notices.

15.1 General. Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Either Party may change the notice information in this LGIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given

in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Party in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

Article 16. Force Majeure

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

Article 17. Default

17.1 Default

17.1.1 **General.** No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act of omission of the other Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 **Right to Terminate.** If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this LGIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this LGIA.

Article 18. Indemnity, Consequential Damages and Insurance

18.1 **Indemnity.** The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this LGIA on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnified Party.

18.1.1 **Indemnified Person.** If an Indemnified Person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such Indemnified Person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 **Indemnifying Party.** If an Indemnifying Party is obligated to indemnify and hold any Indemnified Person harmless under this Article 18, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

18.1.3 **Indemnity Procedures.** Promptly after receipt by an Indemnified Person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Person shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the Indemnifying Party and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the Indemnifying Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses.

The Indemnified Person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the Indemnified Person and the Indemnifying Party, in such event the Indemnifying Party shall pay the reasonable expenses of the Indemnified

Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be reasonably withheld, conditioned or delayed.

18.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 Insurance. Each party shall, at its own expense, maintain in force throughout the period of this LGIA, and until released by the other Party, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this LGIA.

18.3.9 Within ten (10) days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, each Party shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

Article 19. Assignment

19.1 **Assignment.** This LGIA may be assigned by either Party only with the written consent of the other; provided that either Party may assign this LGIA without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this LGIA; and provided further that Interconnection Customer shall have the right to assign this LGIA, without the consent of Transmission Provider, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that Interconnection Customer will promptly notify Transmission Provider of any such assignment. Any financing arrangement entered into by Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured Party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider of the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

Article 20. Severability

20.1 Severability. If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Provider) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

Article 21. Comparability

21.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

Article 22. Confidentiality

22.1 Confidentiality. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 Term. During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of the LGIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

22.1.3 Release of Confidential Information. Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential

Information in contravention of this Article 22.

22.1.4 **Rights.** Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 **No Warranties.** By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 **Standard of Care.** Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this LGIA or its regulatory requirements.

22.1.7 **Order of Disclosure.** If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such

request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this LGIA.

Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 **Termination of Agreement.** Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

22.1.9 **Remedies.** The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants

contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 **Disclosure to FERC, its Staff, or a State.** Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 CFR section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this LGIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party

claims is competitively sensitive, commercial or financial information under this LGIA ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

Article 23. Environmental Releases

23.1 Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the

Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

Article 24. Information Requirements

24.1 Information Acquisition. Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 Information Submission by Transmission Provider. The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 Updated Information Submission by Interconnection Customer. The updated information submission by Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Trial Operation. Interconnection Customer shall submit a completed copy of the Large Generating Facility data

requirements contained in Appendix 1 to the LGIP. It shall also include any additional information provided to Transmission Provider for the Feasibility and Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study Agreement between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on Transmission Provider Transmission System based on the actual data submitted pursuant to this Article 24.3. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

24.4 Information Supplementation. Prior to the Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Large Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Large Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Large Generating Facility to verify proper operation of the Large Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Large Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent change in Large Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the

responses of Large Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Large Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Large Generating Facility terminal or field voltages is provided. Large Generating Facility testing shall be conducted and results provided to Transmission Provider for each individual generating unit in a station.

Subsequent to the Operation Date, Interconnection Customer shall provide Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Provider shall provide Interconnection Customer any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Provider-owned substation that may affect Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

Article 25. Information Access and Audit Rights

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Party information that is in the possession of the disclosing Party and is necessary in order for the other Party to: (i) verify the costs incurred by the disclosing Party for which the other Party is responsible under this LGIA; and (ii) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA.

25.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Party when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The

Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this LGIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this LGIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party, to audit at its own expense the other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this LGIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this LGIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods.

25.4.1 **Audit Rights Period for Construction-Related Accounts and Records.** Accounts and records related to the design, engineering, procurement, and construction of Transmission Provider's Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission

Provider's issuance of a final invoice in accordance with Article 12.2.

25.4.2 **Audit Rights Period for All Other Accounts and Records.** Accounts and records related to either Party's performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

25.5 **Audit Results.** If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

Article 26. Subcontractors

26.1 **General.** Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

26.2 **Responsibility of Principal.** The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Provider be liable for the actions or

inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

Article 27. Disputes

27.1 Submission. In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 External Arbitration Procedures. Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third

arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail.

27.3 Arbitration Decisions. Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

27.4 Costs. Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

Article 28. Representations, Warranties, and Covenants

28.1 General. Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 Authority. Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 No Conflict. The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any

judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 **Consent and Approval.** Such Party has sought or obtained, or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

Article 29. Joint Operating Committee

29.1 Joint Operating Committee. Except in the case of ISOs and RTOs, Transmission Provider shall constitute a Joint Operating Committee to coordinate operating and technical considerations of Interconnection Service. At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Interconnection Customer shall notify Transmission Provider of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of either Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this LGIA. Each Party shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

29.1.1 Establish data requirements and operating record requirements.

29.1.2 Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

29.1.3 Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Provider's and Interconnection Customer's facilities at the Point of Interconnection.

29.1.4 Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Large Generating Facility and other facilities that impact the normal operation of the interconnection of the Large Generating Facility to the Transmission System.

29.1.5 Ensure that information is being provided by each Party regarding equipment availability.

29.1.6 Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

Article 30. Miscellaneous

30.1 Binding Effect. This LGIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts. In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation. This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix to this LGIA, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 Entire Agreement. This LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this LGIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this LGIA.

30.5 **No Third Party Beneficiaries.** This LGIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 **Waiver.** The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party. Any waiver at any time by either Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this LGIA. Termination or Default of this LGIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 **Headings.** The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

30.8 **Multiple Counterparts.** This LGIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 **Amendment.** The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by the Parties.

30.10 **Modification by the Parties.** The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. Transmission Provider shall have the right to make a unilateral filing with FERC to modify this LGIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

IN WITNESS WHEREOF, the Parties have executed this LGIA in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

PACIFICORP, on behalf of its Transmission function

By: Rick Vail Digitally signed by Rick Vail Date: 2019.09.12 07:20:30 -07'00'

Rick Vail

Title: VP, Transmission

Date: 9/12/2019

PACIFICORP, on behalf of its Marketing function

By:

Chad A. Teply

Title: Senior Vice President

Date: Sept. 10, 2019

Appendix A to LGIA

Interconnection Facilities, Network Upgrades, Distribution Upgrades, and Contingent Facilities

1. **Interconnection Facilities:**

   (a) **Interconnection Customer's Interconnection Facilities:** includes one 34.5 kV/230 kV transformer and high-side circuit breaker and a short line segment to the Point of Interconnection.

   (b) **Transmission Provider's Interconnection Facilities:** includes a take-off structure inside the Point of Interconnection substation; 230 kV interchange meter and associated instrument transformers.

2. **Network Upgrades:**

   (a) **Stand Alone Network Upgrades:** includes the installation of a new three-breaker ring bus substation (and appurtenances thereof).

   (b) **Other Network Upgrades:** includes approximately 55 miles of fiber optic cable from Point of Interconnection substation to Frannie and Yellowtail substations; installation of communications equipment at various Transmission Provider locations and a new transmission line loop in/out of the 230 kV Frannie-Yellowtail transmission line to the Point of Interconnection substation.

3. **Distribution Upgrades:** None

4. **Contingent Facilities:** As identified in the System Impact Study for this project dated August 14, 2014 and the Facilities Study dated January 14, 2015, the following Network Upgrades are required to be in-service prior to this project:

   - None identified

5. Point of Interconnection: the point at which Transmission Provider's Interconnection Facilities connect to the Point of Interconnection substation's bus.

6. Point of Change of Ownership: the point at which the conductor from final structure of Interconnection Customer's generation tie line meets Transmission Provider's take-off structure.

7. One-Line Diagram: please see Exhibit 1 to Appendix A to Agreement.

8. Estimated Cost:

Direct Assigned:	$451,000
Network Upgrade:	$13,990,000
Total:	$14,441,000

Appendix B To LGIA

Milestones

Interconnection Customer executes Interconnection Agreement, authorizes the start of engineering and procurement, and provides financial security pursuant to Article 11.5, in the amount of $3,390,000: September 6, 2019

Interconnection Customer and Transmission Provider to begin detailed engineering activities: September 9, 2019

Interconnection Customer to provide Transmission Provider with all required rights of way/easements/permits/property rights: October 16, 2019

Interconnection Customer provides Transmission Provider with required modeling information to satisfy Transmission Provider’s Energy Imbalance Market requirement: October 25, 2019

Transmission Provider Engineering Design Complete: March 19, 2020

Interconnection Customer authorizes construction: April 20, 2020

Transmission Provider commences construction: May 18, 2020

Transmission Provider and Interconnection Customer construction complete: August 3, 2020

Transmission Provider commissioning activities complete: August 25, 2020

Transmission Provider commissioning document review complete: August 28, 2020

Interconnection Customer facility receives backfeed power: September 1, 2020

Interconnection Customer shall request permission to backfeed in writing, including by e-mail, and wait to receive written permission from the Transmission Provider.

Initial Synchronization/Generator Testing Commencement: September 22, 2020

Interconnection Customer shall request permission for initial synchronization in writing, including by e-mail, and wait to receive written permission from the Transmission Provider. Interconnection Customer will be required to demonstrate the reactive capability of the facility and the voltage control system prior to commercial operation.

Commercial Operation Date: September 25, 2020

Interconnection Customer shall request permission for commercial operation in writing, including by e-mail, and wait to receive written permission from the Transmission Provider. As soon as possible Interconnection Customer shall confirm the actual Commercial Operation Date by submitting Appendix E to the Transmission Provider.

Appendix C To LGIA

Interconnection Details

Description of the Large Generating Facility: Consists of 57 Vestas V110-2.0MK10B, 24 Vestas V110-2.2MK10C, 29 Vestas V110-2.2MK10D, and 4 GE2.3-116 wind turbine generators for a full output of 240 MW as measured at the Point of Interconnection. Turbine strings are connected to two 34.5-230 kV, 90/120/150 MVA step up transformer with impedance of 9%.

Please see Exhibit 1 to Attachment A.

Control Area Requirements: Interconnection Customer shall interconnect and operate the Large Generating Facility in accordance with the Transmission Provider's Facility Interconnection Requirements for Transmission Systems, as may be revised from time to time, attached hereto as Exhibit 1 to Appendix C and by this reference incorporated herein.

Interconnection Details:
Metering. With reference to Article 7.1, Transmission Provider will own and maintain the bi-directional revenue Metering Equipment in Transmission Provider's Point of Interconnection substation at the Interconnection Customer's expense.

Under Frequency and Over Frequency Conditions. Consistent with LGIA Article 9.7.3, Transmission Provider shall design, procure, install and maintain frequency and voltage protection to trip feeder breakers in accordance with the settings shown in Exhibit 1 to Appendix C.

Reactive Power and Voltage Schedule. All interconnecting synchronous and non-synchronous generators are required to design their Generating Facilities with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices. For non-synchronous generators, the power factor requirement is to be measured at the high-side of the generator substation. The Generating Facility must provide dynamic reactive power to the system over the full range of real power output. If the Generating

Facility is not capable of providing positive reactive support (i.e., supplying reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations, the facility will be required to add dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.

Generators shall be equipped with automatic voltage-control equipment and normally operated with the voltage regulation control mode enabled unless written authorization, or directive, from the Transmission Provider is given to operate in another control mode (e.g., constant power factor control). The control mode of generating units shall be accurately represented in operating studies. The generators shall be capable of operating continuously at their rated power output within +/- 5% of its rated terminal voltage. Phasor Measurement Units will be required at any Generating Facilities with an individual or aggregate nameplate capacity of 75 MVA or greater.

As required by NERC standard VAR-001-1a, the Transmission Provider will provide a voltage schedule for the Point of Interconnection. In general, Generating Facilities should be operated so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Transmission Provider, in accordance with Transmission Provider Policy 139.

Generating Facilities capable of operating with a voltage droop are required to do so. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer’s responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing. If the need for a master controller is identified, the cost and all related installation requirements will be the responsibility of the Interconnection Customer. Participation by the Generation Facility in subsequent interaction/coordination studies will be required pre- and post-commercial operation in order ensure system reliability.

All generators must meet the Federal Energy Regulatory Commission (FERC) and WECC low voltage ride-through requirements.

As the Transmission Provider cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

Property Requirements. Subject to LGIA Articles 5.12 and 5.13, Interconnection Customer is required to obtain for the benefit of Transmission Provider at Interconnection Customer’s sole cost and expense all real property rights, including but not limited to fee ownership, easements and/or rights of way, as applicable, for Transmission Provider owned facilities using forms acceptable to Transmission Provider. Transmission Provider shall not be obligated to accept any such real property right that does not, at Transmission Provider’s sole discretion, confer sufficient rights to access, operate, construct, modify, maintain, place and remove Transmission Provider owned facilities or is otherwise conveyed using forms unacceptable to Transmission Provider. Further, all real property on which Transmission Provider’s facilities are to be located must be environmentally, physically and operationally acceptable to the Transmission Provider in accordance with Good Utility Practice.

Subject to LGIA Article 5.14, Interconnection Customer is responsible for obtaining all permits required by all relevant jurisdictions for the project, including but not limited to, conditional use permits and construction permits; provided however, Transmission Provider shall obtain, at Interconnection Customer’s cost and schedule risk, the permits necessary to construct Transmission Provider’s facilities that are to be located on real property currently owned or held in fee or right by Transmission Provider.

Subject to applicable provisions in the Agreement and an express written waiver by an authorized officer of Transmission Provider, all of the foregoing permits and real property rights (conferring rights on real property that is environmentally, physically and operationally acceptable to Transmission Provider) shall be acquired as provided herein as a condition to Transmission Provider’s contractual obligation to construct or take possession of facilities to be owned by the Transmission Provider under this Agreement. Transmission Provider shall have no liability for any project delays or cost overruns caused by delays in acquiring any of the foregoing permits and/or real property rights, whether such delay results from the failure to obtain such permits or rights or the failure of such permits or rights to meet the requirements set forth herein. Further, any completion dates, if any, set forth herein with regard to Transmission Provider’s obligations shall be equitably extended based on the length and impact of any such delays.

With respect to the fiber optic cable on Interconnection Customer’s tie line that will be owned by the Transmission Provider, the Interconnection Customer and the Transmission Provider agree that Transmission Provider’s ownership and operation of fiber optic cable that is attached to poles or other structures that are owned or maintained by the Interconnection Customer is subject to LGIA Article 5.12, Good Utility Practice, and Transmission Provider’s Interconnection Policy 139 (Exhibit 1 to Appendix C to LGIA).

Appendix D To LGIA

Security Arrangements Details

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

Automatic Data Transfer. Throughout the term of this Agreement, Interconnection Customer shall provide the data specified below by automatic data transfer to the Transmission Provider Control Center specified by Transmission Provider or to a Third-Party System Operator designated by Transmission Provider (or both):

Analogs:

- o Real power flow 34.5 kV line #1
- o Reactive power flow 34.5 kV line #1
- o Real power flow 34.5 kV line #2
- o Reactive power flow 34.5 kV line #2
- o Real power flow 34.5 kV line #3
- o Reactive power flow 34.5 kV line #3
- o Real power flow 34.5 kV line #4
- o Reactive power flow 34.5 kV line #4
- o Real power flow 34.5 kV line #5
- o Reactive power flow 34.5 kV line #5
- o Real power flow 34.5 kV line #6
- o Reactive power flow 34.5 kV line #6
- o Real power flow 34.5 kV line #7
- o Reactive power flow 34.5 kV line #7
- o Real power flow 34.5 kV line #8
- o Reactive power flow 34.5 kV line #8
- o Real power flow 34.5 kV line #9
- o Reactive power flow 34.5 kV line #9
- o Real power flow 34.5 kV line #10
- o Reactive power flow 34.5 kV line #10

- o Average Wind Farm Wind Speed (m/s)
- o Average Wind Farm Atmospheric Pressure (Bar)
- o Average Wind Farm Temperature (Celsius)

Status:

- o 230 kV transformer breaker
- o 34.5 kV transformer breaker
- o 34.5 kV Line #1 breaker
- o 34.5 kV Line #2 breaker
- o 34.5 kV Line #3 breaker
- o 34.5 kV Line #4 breaker
- o 34.5 kV Line #5 breaker
- o 34.5 kV Line #6 breaker
- o 34.5 kV Line #7 breaker
- o 34.5 kV Line #8 breaker
- o 34.5 kV Line #9 breaker
- o 34.5 kV Line #10 breaker

Billing Meter Data. Bi-directional revenue meters at the Point of Interconnection Substation shall not be configured to allow direct dial-up access by Interconnection Customer. The Transmission Provider will provide alternatives at the Interconnection Customer's expense, upon request.

Additional Data. Interconnection Customer shall, at its sole expense, provide any additional Generating Facility data reasonably required and necessary for the Transmission Provider to operate the Transmission System in accordance with Good Utility Practice and Exhibit 1 to Appendix C, Facility Connection Requirements for Transmission Systems.

Relay and Control Settings

If Interconnection Customer requires modifications to the settings associated with control/protective devices connected to the distribution and/or transmission system, Interconnection Customer will contact PacifiCorp and provide in writing the justification for the proposed modifications. This will allow PacifiCorp to analyze the modifications and ensure there will be no negative impacts to connected systems and customers. PacifiCorp will provided timely review of proposed modifications and decisions regarding the proposed modifications thereof.

Appendix E To LGIA

Commercial Operation Date

This Appendix E is a part of the LGIA between Transmission Provider and Interconnection Customer.

[Date]

[Transmission Provider Address]

Re: ________________ Large Generating Facility

Dear ________________:

On **[Date] [Interconnection Customer]** has completed Trial Operation of Unit No. __. This letter confirms that [Interconnection Customer] commenced Commercial Operation of Unit No. ___ at the Large Generating Facility, effective as of **[Date plus one day]**.

Thank you.

[Signature]

[Interconnection Customer Representative]

Appendix F to LGIA

Addresses for Delivery of Notices and Billings

Notices, Billings and Payments:

Transmission Provider:

US Mail Deliveries: PacifiCorp Transmission Services
Attn: Central Cashiers Office
PO Box 2757
Portland, OR 97208-2757

Other Deliveries: Central Cashiers Office
Attn: PacifiCorp Transmission Services
825 NE Multnomah Street, Suite 550
Portland OR 97232

Phone Number: [Add Central Cashiers Phone Number]

Interconnection Customer:

[To be supplied.]

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

Director, Transmission Services	[Add Number]
Manager, Transmission Scheduling	[Add Number]
Manager, Interconnection Services	[Add Number]
Manager, Transmission Services	[Add Number]
Transmission Business Facsimile	[Add Number]

OASIS Address:
http://www.oasis.pacificorp.com/oasis/ppw/main.htmlx

Interconnection Customer:

Appendix G to LGIA

INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. <u>Technical Standards Applicable to a Wind Generating Plant</u>

i. <u>Low Voltage Ride-Through (LVRT) Capability</u>

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

<u>Transition Period LVRT Standard</u>

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating

plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or "GSU"), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the

fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. <u>Power Factor Design Criteria (Reactive Power)</u>

The following reactive power requirements apply only to a newly interconnecting wind generating plant that has executed a Facilities Study Agreement as of the effective

date of the Final Rule establishing the reactive power requirements for non-synchronous generators in section 9.6.1 of this LGIA (Order No. 827). A wind generating plant to which this provision applies shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

Exhibit 1 to Appendix A to LGIA

One-Line Diagram

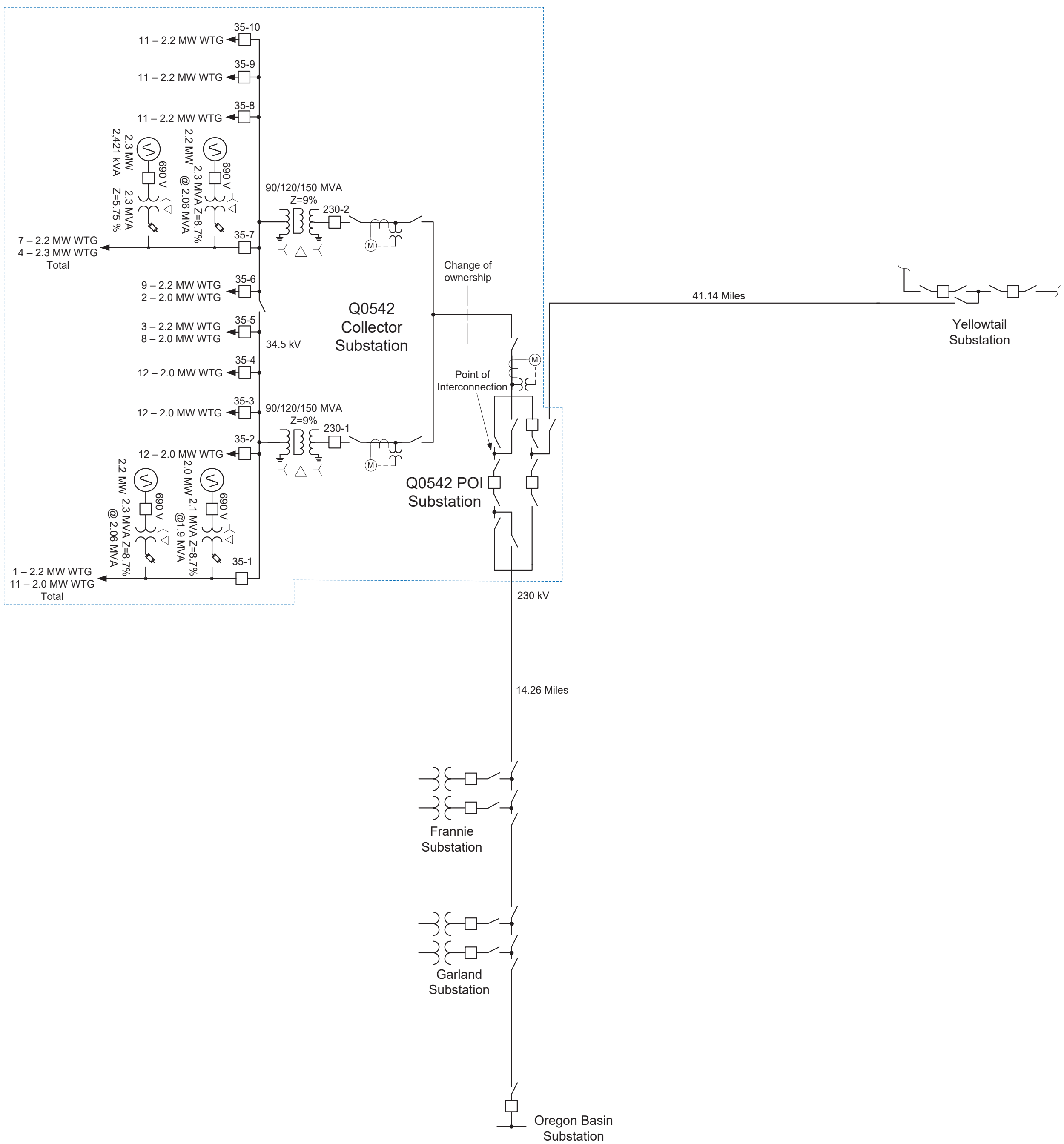

Exhibit 2 to Appendix A to LGIA

Scope of Work

Interconnection Customer Generating Facility and Collector Substation

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer's Generation Facility and associated collector substation.

Interconnection Customer Requirements

- Procure all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the Interconnection Customer's Generating Facility and collector substation.
- Design, procure, construct, own and maintain the Interconnection Customer's Generating Facility and associated collector substation. The collector substation is to be constructed adjacent to (within 800' between deadend structures) the new POI substation.
- Design the Generating Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer's GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the generating facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Generating Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Transmission Provider.
- Install a Phasor Measurement Unit to collect data from the Project. The data must be collected and be able to stream to the Planning Coordinator for each of the Generator

Facility's step-up transformers measured on the low side of the GSU at a sample rate of at least 60 samples per second and synchronized within +/- 2 milliseconds of the Coordinated Universal Time (UTC). Initially, the following data must be collected:

- o Three phase voltage and voltage angle (analog)
- o Three phase current (analog)

Data requirements are subject to change as deemed necessary to comply with local and federal regulations.

- Operate the Generating Facility so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriate by Transmission Provider, at a voltage schedule to be provided by the Transmission Provider following testing. Voltage will typically be required to operate between 1.00 and 1.04 per unit.
- Operate the Generating Facility with a voltage droop.
- Have any Transmission Provider required studies, such as a voltage coordination study, performed and provide results to Transmission Provider. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Meet the Federal Energy Regulatory Commission (FERC) and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide the Transmission Provider a standard model from the WECC Approved Dynamic Model Library.
- Design and construct the collector substation such that the ground grid can be connected to the POI substation ground grid to support the installation of a Transmission Provider owned and maintained bus differential scheme. The Interconnection Customer is responsible to ensure the ground grid design supports safe step and touch potentials.
- Design, provide and install conduits between the Interconnection Customer collector substation and the marshalling cabinet to be installed just inside the fence of the POI substation to support copper circuits installed between the facilities.
- Provide and install two sets of current transformers to be fed into the bus differential relays with a maximum current transformer ratio matching the maximum CT ratio of the breakers at the POI substation. Provide and install conduit and cabling to the POI substation marshalling cabinet with these outputs.
- Design, provide and install control cabling (number and size TBD) and hard wire the Interconnection Customer's

source devices to the marshalling cabinet. Replicated values are not acceptable.

- Provide the following data points from the collector substation via hardwire to the marshalling cabinet located in the POI substation. Please note that these points are based on the most recent design information provided by the Interconnection Customer and could change based on final design:

  Analogs:
    - Real power flow 34.5 kV line #1
    - Reactive power flow 34.5 kV line #1
    - Real power flow 34.5 kV line #2
    - Reactive power flow 34.5 kV line #2
    - Real power flow 34.5 kV line #3
    - Reactive power flow 34.5 kV line #3
    - Real power flow 34.5 kV line #4
    - Reactive power flow 34.5 kV line #4
    - Real power flow 34.5 kV line #5
    - Reactive power flow 34.5 kV line #5
    - Real power flow 34.5 kV line #6
    - Reactive power flow 34.5 kV line #6
    - Real power flow 34.5 kV line #7
    - Reactive power flow 34.5 kV line #7
    - Real power flow 34.5 kV line #8
    - Reactive power flow 34.5 kV line #8
    - Real power flow 34.5 kV line #9
    - Reactive power flow 34.5 kV line #9
    - Real power flow 34.5 kV line #10
    - Reactive power flow 34.5 kV line #10
    - Average Wind Farm Wind Speed (m/s)
    - Average Wind Farm Atmospheric Pressure (Bar)
    - Average Wind Farm Temperature (Celsius)

  Status:
    - 230 kV transformer breaker
    - 34.5 kV transformer breaker
    - 34.5 kV Line #1 breaker
    - 34.5 kV Line #2 breaker
    - 34.5 kV Line #3 breaker
    - 34.5 kV Line #4 breaker
    - 34.5 kV Line #5 breaker
    - 34.5 kV Line #6 breaker
    - 34.5 kV Line #7 breaker
    - 34.5 kV Line #8 breaker
    - 34.5 kV Line #9 breaker
    - 34.5 kV Line #10 breaker
- Provide and install conductor, shield wire and line hardware in sufficient quantities to allow the Transmission

Provider to terminate the segment running from the collector substation deadend structure into the POI substation deadend structure. The last segment will be owned by the Transmission Provider.

- Procure and install Transmission Provider approved H-Frame structures for both sets of the Transmission Provider's 230 kV instrument transformers to be installed on the high side of both of the Interconnection Customer's main step up transformers. The installation location shall be coordinated with the Transmission Provider.
- Install the Transmission Provider's provided instrument transformers.
- Install complete conduit and control cable provided by the Transmission Provider from both sets of the Transmission Provider's instrument transformers to the Transmission Provider's POI substation fence line.
- Provide Transmission Provider unfettered and maintained access to the Transmission Provider's instrument transformers.
- Arrange for and provide permanent retail service for power that will flow from the Transmission Provider's system when the Project is not generating with the retail service provider in this area. This will require the retail service provider to obtain transmission service from the Transmission Provider. These arrangements must be in place prior to approval for backfeed.
- Provide any construction or backup retail service necessary for the Project.

Transmission Provider Requirements

- Provide the Interconnection Customer the designated point at which the voltage is to be maintained and the associated voltage schedule.
- Identify any necessary studies that the Interconnection Customer must have performed.
- Identify the values to be stored in the PMU.
- Provide the Interconnection Customer the necessary specifications to allow the ground grid of the Interconnection Customer's collector substation and the POI substation to be tied together.
- Provide the Interconnection Customer the necessary specifications for the bus between the Interconnection Customer's collector substation and the new POI substation to be connected.

- Coordinate with Interconnection Customer on the location, size, and types of conduits and control cables between the POI substation and the collector substation.
- Provide the Interconnection Customer the specifications for the instrument transformer structures.
- Provide the control cable to be installed by the Interconnection Customer from the instrument transformers to the Transmission Provider’s POI substation fence and coordinate on the location of the cable.
- Procure and provide to the Interconnection Customer the 230 kV instrument transformers to be installed on the high side of both the Interconnection Customer’s main step up transformers.

Point of Interconnection Substation

The following outlines the design, procurement, construction, installation, and ownership of equipment at the new Point of Interconnection substation.

Interconnection Customer Requirements

- Provide all necessary easements, rights of way, and land acquisition on Transmission Provider’s standard forms as required to facilitate the construction of the Transmission Provider’s new POI substation.
- Provide a separate graded, grounded and fenced area adjacent to (sharing a common fence) the Interconnection Customer’s collector substation for the Transmission Provider’s POI substation as required by the Transmission Provider’s site work design specifications and drawings.

Transmission Provider Requirements

- Support the Interconnection Customer’s efforts to procure all necessary easements, rights of way and land acquisition for the construction of the new POI substation.
- Design, procure and construct a new 230 kV three breaker ring bus substation adjacent to the Interconnection Customer’s collector substation which will include the following major pieces of equipment:
    - (3) – 230kV, breaker
    - (6) – 230kV, CCVT
    - (3) – 230kV, combined CT/VT metering unit
    - (8) – 230kV, switch, breaker disconnect
    - (3) – 230kV, switch, line disconnect
    - (1) – 230 kV, switch, meter disconnect
    - (9) – 230kV, lightning arrester
    - (1) – 230 kV, SSVT

   - (1) – control house

- Perform a CDEGS grounding analysis to determine requirements for both the Interconnection Customer collector substation and Transmission Provider POI substation. Provide requirements to Interconnection Customer.
- Terminate the transmission lines running from Frannie and Yellowtail substations into the POI substation dead-end structures.
- Terminate the last bus/line segment running from the Interconnection Customer's collector substation deadend structure into the POI substation deadend structure using Interconnection Customer provided and installed conductor, shield wire and line hardware.
- Design, procure and install a marshalling cabinet near the Interconnection Customer's collector substation shared fence line.
- Provide and install conduit and control cabling between the marshalling cabinet and the control building and bus differential cabinet.
- Design, procure and install a redundant bus differential relay system for the connection to the Interconnection Customer's collector substation.
- Procure and install a relay for under/over voltage and over/under frequency protection of the system.
- Procure and install a set of line current differential relay systems for the lines to both Frannie and Yellowtail substations. The relays will use permissive overreaching transfer trip logic.
- Include the following data points from the new POI substation into the new substation RTU:
  <u>Analogs:</u>
   - Net Generation MW
   - Net Generator MVAR
   - Interchange metering kWH
- Procure and install the necessary communication equipment to tie the new POI substation RTU into the Transmission Provider's communications network including fiber nodes, multiplex, router, battery system and charger.
- Provide and install fiber between the control building and the OPGW to be installed on the line to Frannie substation.
- Provide and install fiber between the control building and the OPGW to be installed on the line to Yellowtail substation.

- Install line loss logic equipment to support the required remedial action scheme ("RAS").
- Design, procure and install 230 kV revenue metering equipment including two (2) revenue quality meters, test switch, instrument transformers, metering panels, junction box and secondary metering wire at the Point of Interconnection.
- Design, procure and install two sets of 230 kV revenue metering equipment including revenue quality meters, test switches, metering panels, junction boxes and secondary metering wire for each of the two Interconnection Customer step up transformers.
- Provide and install an Ethernet connection for retail sales and generation accounting via the MV-90 translation system.
- Procure and install AC and DC service for the new POI substation.
- If requested, install a metering cabinet on the exterior of the POI substation fence in order to provide a Modbus or DNP output from the bidirectional meters to the retail service provider. The Transmission Provider will install an underground communication wire from the POI substation control building to the meter panel.

Other Substations/Remote Sites

The following outlines the design, procurement, construction, installation, and ownership of equipment at locations past the Point of Interconnection on the Transmission Provider's system.

<u>Work to be completed by the Transmission Provider</u>

- Oregon Basin-Yellowtail Transmission Line
    - Loop the line in and out of the new Point of Interconnection substation which will require the installation of four transmission structures and approximately 800 feet of conductor.
    - Install approximately 14 miles of fiber optic cable from the new Point of Interconnection substation to Frannie substation in place of one of the existing shield wires. Splice to fiber running from the substation control buildings. This will require the correction of approximately 15 structural defects.
    - Install approximately 41 miles of fiber optic cable from the new Point of Interconnection substation to Yellowtail substation in place of

  one of the existing shield wires. Splice to fiber running from the substation control buildings. This will require the correction of approximately 40 structural defects.
  - Remove the existing power line carrier and utilize mirrored bits to interface with McCullough Peak communications site.

- Frannie Substation
  - Provide and install fiber between the control building and the OPGW to be installed on the line to the new Point of Interconnection substation.
  - Install the necessary communications equipment to tie in the new fiber optic cable.
  - Modify relay settings to coordinate with the relays in the Point of Interconnection substation.
  - Procure and install a microwave system including tower, communications equipment and backup power system.
  - Remove existing wave trap and power line carrier equipment.

- Yellowtail Substation
  - Provide and install fiber between the substation control building and the OPGW to be installed on the line to the new POI substation.
  - Install the necessary communications equipment to tie in the fiber optic cable.
  - Remove existing wave trap and power line carrier equipment.
  - Modify relay settings to coordinate with the relays in the Point of Interconnection substation.
  - Install a line loss logic panel to support the RAS.

- Oregon Basin Substation
  - Procure any necessary property rights in order to allow for the substation fence to be expanded.
  - Expand the substation fence as necessary to develop sufficient space for the installation of a new control building and microwave tower.
  - Move existing substation infrastructure to allow for the construction of a new control building adjacent to the existing substation control building.
  - Procure and install a microwave system including tower, communications equipment and backup power system.

  - o Remove existing wave trap and power line carrier equipment.

- McCullough Peak Communications Site
  - o Procure and install the necessary communications equipment to interface with the new microwave systems being installed at various substations.

- Cody Service Center
  - o Procure and install a microwave system including tower, communications equipment and backup power system.

- Casper Service Center
  - o Modify the existing communications equipment to allow data from the Generating Facility to be captured.

- Remedial Action Scheme
  - o Design and implement a RAS to disconnect the Interconnection Customer's Large Generating Facility for an outage of the transmission line between the new POI substation and Yellowtail substation under certain heavy load, heavy generation conditions.
  - o If necessary, present for approval any generator tripping/load reduction schemes to the WECC Remedial Action Scheme Reliability Subcommittee ("RASRS").

- System Operations Centers
  - o Update databases to include the Interconnection Customer's Generating Facility along with Interconnection Facilities and Network Upgrades.

Exhibit 1 to Appendix C to LGIA

Facility Connection Requirements for Transmission Systems

REDACTED
Docket No. UE 374
Exhibit PAC/825
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

Pryor Mountain Rights of Way

February 2020

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

Docket No. UE 374
Exhibit PAC/826
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

Permit Status Record Pryor Mountain

February 2020

Agency	Permit or Needed Action	Information Regarding Permit or Action Requirements	Notes
Federal			
Environmental Protection Agency (EPA) in coordination with the State Regulatory Authority	Phase I Environmental Site Assessment	A report prepared for a real estate holding that identifies potential or existing environmental contamination liabilities. No submittal required to EPA	Complete
	Spill Prevention Control and Countermeasure Plan (SPCC)	Develop and implement SPCC Plans	Pending final design
	National Pollutant Discharge Elimination System Stormwater Permit	NPDES is covered under the Montana SWPPP	Complete
Federal Communications Commission (FCC)	Microwave Study	Rocky Mountain Power study for the POI communications	Complete
Department of Commerce / NTIA	National Telecommunications and Information Administration (NTIA) Filing		Complete
Federal Emergency Management Agency (FEMA)	Flood Plain Designations	Determine areas within 100 year flood plain for financing	Complete
National Historic Preservation Act	Federal Section 106, Class I Literature Review / Class II Architectural Survey/ Class III Cultural Field Survey	Section 106 of the National Historic Preservation Act (NHPA) may be invoked by a Federal Agency if the Project requires federal land, funding, or permits. Seller to complete preliminary Class I literature review of National and State registered sites, and Class II or Class III field survey for preliminary turbine, collection line, and access road layout. No submittal to National Historic Preservation Act required.	Complete
U.S. Army Corps of Engineers (USACE)	Wetland Delineation	Perform desktop review and preliminary field wetland delineation per 1987 Corps Wetland Delineation Manual and Regional Supplements to determine extent of USACE jurisdiction, quantify impacts based on the preliminary turbine, collection line, and access road design (only the intersection between preliminary design and identified wetland features will be delineated).	Complete
	Final Wetland Delineation and Documentation of Impacts	Perform any additional field wetland delineations per 1987 Corps Wetland Delineation Manual and Regional Supplements as necessary due to final design changes, and document avoidance during construction.	Pending final design
	Federal Clean Water Act Section 404 and Section 10 Permit(s)	Required for the discharge of dredged or fill material into waters of U.S. Minimal levels of fill may be covered under existing General Permits/Letters of Permission	Obtained by Contractor as needed

	Agency	Permit or Needed Action	Information Regarding Permit or Action Requirements	Notes
	U.S. Fish and Wildlife Service (USFWS)	Communications and Data	Communications with USFWS per Land-Based Wind Energy Guidelines and Eagle Conservation Plan Guidance	Ongoing
		Land-Based Wind Energy Guidelines Tier 1 Preliminary site evaluation (Eagle Conservation Plan Guidance Stage 1)		Complete
		Land-Based Wind Energy Guidelines Tier 2: Site characterization (Eagle Conservation Plan Guidance Stage 1)	• Assess potential presence of species of concern, including species of habitat fragmentation concern • Assess potential presence of plant communities present on site that may provide habitat for species of concern • Assess potential presence of critical congregation areas for species of concern	Complete
		Land-Based Wind Energy Guidelines Tier 3: Field studies (Eagle Conservation Plan Guidance Stage 2)	Discuss extent and design of field studies to conduct with the Service Conduct biological studies Communicate results of all studies to Service field office	Complete
		Eagle or Protected Species Take Permit, based on results found in Tier 3 Studies	A general conditional application for incidental take by certain hazards of wind farms to birds	Ongoing
		Tier 4: Post construction studies to estimate impacts	Conduct post-construction studies to assess fatalities and habitat-related impacts	Pending construction completion
		Tier 5: Other post-construction studies and research	Conduct appropriate studies as needed Identify potential mitigation strategies to reduce impacts	Pending construction completion
	Federal Aviation Administration (FAA)	Notice of Proposed Construction or Alteration	Determination of No Hazard to Air Navigation needed for each structure over 200 feet tall via form 7460-1.	Complete
		Notice of Actual Construction (Form 7460-2	File 7460-2 within 5 days after the structure reaches its greatest height.	Complete
State				
	Montana Department of Transportation	Highway Crossings/turning lanes/traffic control installations	Required for facilities crossing over or under highways, turning lanes, traffic control devices and highway entrances	Only applies to (2) radii improvements @ Hwy 310. If required
	Montana Department of Labor and Industry	Building Permit	Required for O&M Building	No other building permits required other then O&M

	Agency	Permit or Needed Action	Information Regarding Permit or Action Requirements	Notes
	Montana Department of Environmental Quality	Montana Pollutant Discharge Elimination System Large Construction General Permit (Water Quality)	MPDES is included as part of the SWPPP	Complete
		Temporary / Portable Source Air Permit (Air Quality)	Required for batch plant	Contractor to obtain
		Wastewater Facilities Permit	Septic system permit issued by Carbon County, Montana	Pending final design
		Water Quality – Section 401 Certification	Required after water rights transfer is complete	Pending transfer of water rights
	Montana State Historic Preservation Office	Cultural and Historic Resources Review of State and National Register of Historic Sites and Archeological Survey	Complete Class I literature review collection system, and access road layout	Complete
	Montana Sage Grouse Oversite Team	Communication and Data	Consultation required for SWPPP	Complete
	Montana State Engineer	Water rights change application for Olsen property	State requested we file after construction is complete	Pending construction completion
COUNTY				
	Carbon County	Conditional Use Permit	Required by the county	Complete
	Carbon County	Wastewater Facilities Permit	Septic system permit issued by the county	Pending system design
	Carbon County	Road use agreements		Complete

REDACTED
Docket No. UE 374
Exhibit PAC/827
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

Jim Bridger Unit 3 Cost Comparison

February 2020

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REDACTED
Docket No. UE 374
Exhibit PAC/828
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

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Exhibit Accompanying Direct Testimony of Chad A. Teply

Jim Bridger Unit 4 Cost Comparison

February 2020

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Docket No. UE 374
Exhibit PAC/829
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

PacifiCorp Letter to Wyoming Department of Environmental Quality Air Quality Division

February 2020

MIDAMERICAN
ENERGY HOLDINGS COMPANY

March 5, 2013

Ms. Nancy E. Vehr
Sr. Asst. Attorney General
Wyoming Attorney General's Office
123 Capitol Building
Cheyenne, WY 82002

Mr. Steven A. Dietrich
Air Quality Division Administrator
Wyoming Dept. of Environmental Quality
122 West 25th Street
Cheyenne, WY 82002

Dear Ms. Vehr and Mr. Dietrich:

As a result of the Environmental Protection Agency's upcoming re-proposal of its action on the Wyoming Regional Haze State Implementation Plan (SIP), significant questions have arisen regarding PacifiCorp's obligations to comply with the current compliance deadlines for selective catalytic reduction (SCR) controls at Jim Bridger Units 3 and 4 as contained in the SIP and the Settlement Agreement entered into by PacifiCorp and the Wyoming Department of Environmental Quality in November 2010. The agreements referenced require installation of SCR at Jim Bridger Units 3 and 4 by December 31, 2015, and December 31, 2016, respectively.

During our meeting on January 4, 2013, PacifiCorp posed the following questions to the Wyoming Department of Environmental Quality, Air Quality Division: (1) Does PacifiCorp need to comply with all terms and conditions of the Wyoming SIP prior to EPA action; and (2) will the Air Quality Division consider extending the deadlines for the installation of the SCR at Jim Bridger Units 3 and 4. The Air Quality Division responded that (1) under state regulations, PacifiCorp is required to comply with all terms and conditions of the Wyoming SIP notwithstanding the fact that EPA has not taken action; and (2) that the Air Quality Division considers the requirements to install the Jim Bridger Units 3 and 4 SCR controls as being independently legally enforceable and that the timing of the reductions are necessary to meet the state's requirements to achieve reasonable progress under the regional haze program's requirements.

PacifiCorp hereby requests that the Wyoming Air Quality Division reconsider PacifiCorp's request to change the deadlines for installation of the Jim Bridger Units 3 and 4 SCR controls from December 31, 2015 and December 31, 2016, to five years after EPA's approval of the Wyoming SIP or FIP issuance.

Your prompt response to this request is most appreciated.

Sincerely,

Cathy S. Woollums

Cathy S. Woollums
Sr. Vice President, Environmental and
Chief Environmental Counsel
MidAmerican Energy Holdings Company
106 E. Second Street
Davenport, IA 52801
(563) 333-8009
e-mail: cswoollums@midamerican.com

copies to: Micheal Dunn, PacifiCorp Energy
Chad Teply, PacifiCorp Energy
Bill Lawson, PacifiCorp Energy

Docket No. UE 374
Exhibit PAC/830
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

Wyoming Department of Environmental Quality Air Quality Division Response to PacifiCorp

February 2020

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Matthew H. Mead, Governor **Todd Parfitt, Director**

March 6, 2013

Ms. Cathy S. Woollums
Sr. Vice President, Environmental and
Chief Environmental Counsel
MidAmerican Energy Holdings Company
106 E. Second Street
Davenport, IA 52801

RE: Jim Bridger Units 3 & 4 SCR Controls

Dear Ms. Woollums:

Thank you for your letter, dated March 5, 2013, regarding your concerns about Wyoming's Regional Haze SIP and the November 2010 Settlement Agreement for Jim Bridger Units 3 and 4. In short your concern focuses on the deadline to install selective catalytic reduction (SCR) on these Jim Bridger units.

To start with, DEQ –AQD has stated previously that the terms and conditions of the Wyoming Regional Haze SIP are requirements that PacifiCorp still needs to meet. Under the Wyoming Regional Haze SIP that the State of Wyoming submitted to the EPA in January 2011, PacifiCorp is required to:

> (i) install SCR; (ii) install alternative add-on NOx control systems; or (iii) otherwise reduce NOx emissions to achieve a 0.07 lb/MMBtu 30-day rolling average NOx emissions rate. These installations shall occur, and/or this emission rate will be achieved on Unit 3 prior to December 31, 2015 and Unit 4 prior to December 31, 2016.

See Wyoming State Implementation Plan, Regional Haze, Addressing Regional Haze Requirements for Wyoming mandatory Federal Class I Areas Under 40 CFR 51.309(g), § 8.3.3 Long-Term Control Strategies for BART Facilities (January 7, 2011). Therefore, a change at this time to these requirements would entail a revision to our overall SIP with the EPA. This is one step that the DEQ-AQD does not intend to undertake at this time.

Secondly, you have requested that DEQ reconsider extending the Settlement Agreement deadlines for Jim Bridger Units 3 and 4. Under the Settlement Agreement, PacifiCorp must:

> (i) Install SCR; (ii) install alternative add-on NOx control systems; or (iii) otherwise reduce NOx emissions to achieve a 0.07 lb/mmBtu 30-day rolling average NOx emissions rate. These installations shall occur, and/or this emission rate will be achieved, on Unit 3 prior to December 31, 2015 and Unit 4 prior to December 31, 2016.

See In re: Appeal and Petition for Review of BART Permit No. MD-6040 (Jim Bridger Power Plant); and BART Permit No. MD-6042 (Naughton Power Plant), EQC Docket No. 10-2801, BART Appeal Settlement Agreement, ¶ 4(c) (filed Nov. 9, 2010). The Settlement Agreement may be modified if future changes in: "(i) federal or state requirements or (ii) technology would materially alter the emissions controls and rates that otherwise are required hereunder." *Id.* at ¶ 7. At this time, DEQ-AQD is unaware of any change in federal or state requirements, or technology, that would materially alter the required emissions controls or rates for Jim Bridger Units 3 and 4. Therefore, the DEQ-AQD continues to stand by its January 4, 2013 decision declining to extend the Settlement Agreement deadlines applicable to Jim Bridger Units 3 and 4.

If you would like more information or have additional questions, please contact me by phone at 307-777-7391. We appreciate your continued interest in Wyoming's environment.

Sincerely,

Steven A. Dietrich

Steven A. Dietrich, P.E.
Administrator, AQD

cc: Todd Parfitt, Director
Nancy Vehr, AG Office

Docket No. UE 374
Exhibit PAC/831
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Chad A. Teply

Additional Background Regarding the Regional Haze Compliance Obligations Facing Hunter Unit 1

February 2020

History of Hunter 1 Regional Haze Compliance Obligations

When discussing efforts to establish environmental compliance schedules for PacifiCorp's coal-fueled resources, including Hunter Unit 1, it is imperative to understand the fact that Regional Haze compliance strategies for units across the western U.S. (including Hunter and Huntington) were established via a collective agency, industry and stakeholder approach beginning around the 1999 timeframe (i.e. Western Regional Air Partnership), and with the Regional Haze Rules as they generally exist today promulgated and adopted by the agencies in 2005. Therefore, PacifiCorp's efforts to influence appropriate compliance technologies, compliance deadlines and installation schedules for its individual units affected by Regional Haze Rules began years ago. As a participant in the Western Regional Air Partnership (WRAP) process, the Utah Division of Air Quality established requirements that pollution control equipment, including the installation of the baghouse and LNBs at Hunter 1, would be installed by 2013 (i.e., the end of the 2008 to 2013 Regional Haze Rules BART planning period). PacifiCorp's participation in the WRAP process and Regional Haze planning activities resulted in identifying appropriate emissions control technologies and establishing equipment installation schedules that met the requirements of the state of Utah for Hunter and Huntington and occurred during the units' normally scheduled major overhauls to minimize costs by reducing overall unit down-time and power purchases necessitated by additional outages.

With respect to PacifiCorp's specific efforts to negotiate deferred installation of emissions control equipment on Hunter Unit 1, delays associated with obtaining an approval order and finalizing the Utah Regional Haze State Implementation Plan in the 2008 timeframe made it extremely difficult for PacifiCorp to cost-effectively install the required equipment during the unit's 2010 overhaul, which would have allowed the equipment to be installed in alignment with Utah Regional Haze compliance timeframe requirements prior to 2013. As a result of negotiations with the Utah Division of Air Quality, the Company was allowed to delay the installation of the control equipment on Hunter Unit 1 until the unit's 2014 overhaul. As part of the agreement to delay the installation of the control equipment, PacifiCorp was required to submit semi-annual reports to the state beginning in 2010 demonstrating that continual progress towards completing the installation by 2014 is occurring, and that certain annual emission rates are being met.

With the negotiated 2014 compliance deadline for the baghouse and LNB projects, PacifiCorp completed detailed economic analysis of the Hunter Unit 1 compliance investments in 2012 prior to entering into engineering, procurement, and construction contracts for the multi-year project, incorporating then-current assumptions for forward gas prices, forward market prices, and proxy compliance costs for emerging environmental regulations with the potential to impact the unit. The results of PacifiCorp's economic analyses completed in the 2012 timeframe (and included in Confidential Volume III of the Company's 2013 IRP filing) support investment in the environmental compliance projects, even when considering the reasonably anticipated and generally quantifiable uncertainties regarding emerging environmental compliance obligations for the unit, and continued operation of this low cost resource through its depreciable life.

As has been demonstrated by the EPA's continually delayed and deferred actions regarding Regional Haze Rule action in the state of Wyoming, and with a similar process playing out regarding EPA's delayed and deferred actions on Utah Regional Haze Rule administration, neither Utah nor Wyoming has waited to implement their Regional Haze State Implementation Plans. Instead each state has delivered upon the plans they developed within the construct of the Regional Haze Rules and established timely and enforceable requirements for PacifiCorp's units affected by the rules. The concept of negotiating away compliance obligations while waiting for certainty regarding a myriad of emerging environmental policies and ever changing market conditions is not an approach that the states of Utah and Wyoming have engaged in, particularly without state policy drivers targeting accelerated retirement of the affected low cost resources in question.

REDACTED
Docket No. UE 374
Exhibit PAC/832
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Chad A. Teply

Hunter Unit 1 Analysis and Results

February 2020

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

REDACTED
Docket No. UE 374
Exhibit PAC/900
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Timothy J. Hemstreet

February 2020

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ATTACHED EXHIBITS

Exhibit PAC/901—Major Components of a Wind Turbine Generator

Exhibit PAC/902—Foote Creek I Repowering Project

Confidential Exhibit PAC/903—Foote Creek I Repowering Project Details, Capital Costs, and In-Service Date

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp.

A. My name is Timothy J. Hemstreet. My business address is 825 NE Multnomah Street, Suite 1800, Portland, Oregon 97232. My title is Managing Director of Renewable Energy Development for PacifiCorp. I am testifying for PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

Q. Briefly describe your education and professional experience.

A. I hold a Bachelor of Science degree in Civil Engineering from the University of Notre Dame in Indiana and a Master of Science degree in Civil Engineering from the University of Texas at Austin. I am also a Registered Professional Engineer in the state of Oregon. Before joining PacifiCorp in 2004, I held positions in engineering consulting at CH2M HILL (now Jacobs Engineering, Inc.) and environmental compliance at RR Donnelley Norwest, Inc. Since joining PacifiCorp, I have held positions in environmental policy and compliance, engineering, project management, and hydroelectric project licensing and program management. In 2016, I assumed a role in renewable energy development, focusing on PacifiCorp's wind repowering effort, and assumed my current role in June 2019, in which I oversee the development of renewable energy resources that enhance and complement PacifiCorp's existing renewable energy resource portfolio.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously sponsored testimony in California, Idaho, Oregon, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

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

A. To demonstrate that PacifiCorp's upgrades to "repower" the Foote Creek I wind facility[1] is prudent and in the public interest, my testimony provides the following information:

- The scope of the Foote Creek I repowering project;
- The financial benefits of repowering resulting from the qualification for federal production tax credits (PTCs);
- The increased energy benefits following repowering;
- The reduced ongoing operating costs following repowering;
- The extension of the wind facility asset life after repowering;
- Project implementation status and construction schedule; and
- The disposition of removed equipment.

In addition to cost recovery for repowering the Foote Creek I wind facility, my testimony will describe the Company's hydroelectric generation facilities on the Lewis River in Southwest Washington and the Merwin Fish Collection and Sorting Facility project. My testimony will demonstrate why the Merwin Fish Collection and Sorting Facility project was reasonable and prudent, and should be included in the Company's revenue requirement in this case.

[1] My testimony focuses on Foote Creek 1, the last wind facility to be repowered in PacifiCorp's wind fleet. PacifiCorp filed for recovery of its other repowered wind facilities through its Renewable Adjustment Clause filings in Docket Nos. UE 352 and UE 369.

III. SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. Through its wind repowering project, PacifiCorp is leveraging past investments in its wind fleet and enhancing the future value of these resources for the benefit of its customers. The Company's repowering project is concluding with the Foote Creek I facility—the oldest resource in the Company's wind fleet. Repowering provides a unique opportunity to take advantage of efficiency and reliability improvements in wind generation technology and return PacifiCorp's wind fleet to like-new condition while enhancing performance and minimizing maintenance expenditures.

By incorporating recent technical advances that allow for installation of taller towers, longer blades and nacelles with higher capacity generators, repowering Foote Creek I will result in more low-cost energy for customers. Further, repowering with new equipment will extend the asset life of the wind facility by 21 years, allowing the wind facility to continue serving customers well into the future.

Finally, these repowering benefits can be delivered to customers while reducing, rather than increasing, costs to customers, as further described in the testimony of Mr. Rick T. Link.

In docket UE 352, PacifiCorp received a determination that repowering Glenrock I, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, Marengo I, Marengo II, Goodnoe Hills, and Leaning Juniper was prudent and is receiving or will receive cost recovery of those facilities as they are placed in service.[2] PacifiCorp has requested cost recovery and a determination that repowering

[2] *In the matter of PacifiCorp, dba Pacific Power, 2019 Renewable Adjustment Clause,* Docket No. UE 352, Order No. 19-304 (Sept. 16, 2019) (adopting all-party stipulation issued September 16, 2019).

the Glenrock III and Dunlap wind facilities is prudent in docket UE 369.[3] PacifiCorp's request in this general rate case is for a prudence determination and cost recovery for repowering the Foote Creek I wind facility which is the final facility in PacifiCorp's wind fleet to be repowered.

Following my testimony regarding the wind repowering project, I will describe the Lewis River hydroelectric projects, specifically the Merwin Fish Collection and Sorting Facility project. The Merwin Fish Collection and Sorting Facility project was required by the Lewis River Settlement Agreement and the Federal Energy Regulatory Commission (FERC) licenses issued to the Company for the Merwin, Yale and Swift No. 1 Hydroelectric Projects. Compliance with these license requirements allows customers to continue to benefit from these low-cost, zero-emission hydroelectric resources on the Lewis River during the 50-year license term for these projects.

IV. OVERVIEW OF WIND REPOWERING AND PROJECT SCOPE

Q. Please briefly describe what repowering a wind facility entails.

A. Repowering broadly describes the upgrade of an existing, operating wind facility with new wind-turbine-generator (WTG) equipment that can increase a facility's generating capacity and the amount of electrical generation produced from the facility. Specifically, PacifiCorp's repowering effort has involved replacing the nacelle, hub and rotor of the WTG at all facilities, except the Foote Creek I facility, where repowering will involve replacement of the existing WTGs, including the foundations and towers. *See* Exhibit PAC/901 for a depiction of a wind turbine and

[3] *In the matter of PacifiCorp, dba Pacific Power, 2020 Renewable Adjustment Clause,* Docket No. UE 369, Stipulation (Jan. 31, 2020).

its various components.

Q. Which facilities have been or will be repowered?

A. PacifiCorp has or will repower the facilities known as High Plains, Glenrock I, Glenrock III, Goodnoe Hills, Leaning Juniper, Marengo I, Marengo II, McFadden Ridge, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, Dunlap, and Foote Creek I.

Q. How many megawatts (MW) of installed wind capacity is PacifiCorp repowering?

A. PacifiCorp is repowering all of its 13 wind facilities in 2019 and 2020, representing 1,040 MW of installed wind capacity. Detailed information about the wind facilities was provided in dockets UE 352 and UE 369.[4] Detailed information about Foote Creek I is included in Exhibit PAC/902.

Q. Please explain what repowering at the Foote Creek I wind facility involves.

A. The wind facilities PacifiCorp is repowering began commercial operations between 1999 and 2010. Aside from the Foote Creek I facility, the facilities in PacifiCorp's wind fleet have been economically repowered, or upgraded, with new technology that improves their efficiency and increases their generation output, without incurring the cost to replace the existing towers, foundations, and energy collection systems, which are of sufficient design to accommodate more modern equipment now available. The existing foundations and towers, although more than 10 years old in some instances, are adequately designed to accommodate larger, more modern WTG equipment and still have a sufficient remaining useful life to economically justify the associated

[4] *See* Docket No. UE 352, Exhibit PAC/203; and Docket No. UE 369, Exhibit PAC/204.

investment.

In contrast, at the Foote Creek I facility developed more than 20 years ago, the WTG equipment has a low generating capacity (600 kilowatt) and the towers and foundations supporting the nacelle and rotor do not have the necessary height or design strength to accommodate the installation of modern, larger nacelles and rotors capable of generating a much greater amount of electricity per WTG. Thus, for the Foote Creek I facility, as with older facilities of its type, repowering involves the removal of all of the old wind turbine equipment, including towers, foundations, and energy collection system, and replacement with new equipment and energy collector circuits appropriately sized for the new equipment. Repowering at the Foote Creek I facility will result in the replacement of 68 existing small-capacity wind turbines currently at the site with just 13 modern wind turbines.

Q. When did PacifiCorp initiate its wind repowering project?

A. PacifiCorp began the wind repowering project in the fall of 2016, and authorized the acquisition of safe harbor equipment to facilitate repowering of its fleet of General Electric turbines in early December 2016.

Q. Did PacifiCorp's 2017 Integrated Resource Plan (IRP) evaluate repowering all of the facilities described above?

A. Yes, except for Goodnoe Hills and Foote Creek I. When the 2017 IRP was developed, PacifiCorp had not assessed repowering either Goodnoe Hills or Foote Creek I. After finalization of the 2017 IRP, however, PacifiCorp evaluated repowering both facilities and determined that they could be repowered and provide economic benefits to customers, similar to the other facilities evaluated in the 2017

IRP. Mr. Link describes the Company's analysis of the wind repowering project in the 2017 IRP.

Q. As you note above, the scope of repowering at Foote Creek I is different than repowering at the Company's other wind facilities. Can you provide additional background on the Company's decision to repower Foote Creek I?

A. Foote Creek I was the Company's first wind energy facility. Commercial operation began in April 1999 as a demonstration project to evaluate the feasibility of utility-scale wind energy. The facility was developed in partnership with the Eugene Water & Electric Board (EWEB) and the Bonneville Power Administration (BPA). As developed, Foote Creek I was co-owned by EWEB (21.21 percent ownership) and PacifiCorp (78.79 percent ownership), with BPA taking 37 percent of the facility's output through a 25-year cost-based power purchase agreement (PPA). As the first utility-scale wind energy project in Wyoming, Foote Creek I was sited at one of the most favorable wind sites in the United States and enjoys the highest wind speeds of any of the Company's wind projects. Unlike the remainder of the facilities the Company is repowering, the Foote Creek I project is unique in that it was co-owned and also had a third-party PPA associated with the resource.

The Foote Creek I facility currently consists of 68 turbines with a 600-kilowatt generating capacity, a rotor diameter of 42 meters, and towers that support a 40 meter hub height. Although employing the latest technology when originally installed, the existing turbines are costly to operate and maintain relative to the Company's more modern turbines that have a much higher nameplate capacity, larger rotor diameters, and taller towers. Accordingly, the operations and maintenance costs of the Foote Creek I facility are the highest of all of the Company-owned wind resources on a per-MW basis since the maintenance requirements for these smaller turbines are similar to those of larger turbines, but the capacity of the Foote Creek I turbines is much less.

The costs associated with continued operation of the existing turbines at Foote Creek I for both the Company and EWEB will increase after the expiration of the BPA PPA in April 2024 since 37 percent of these costs would no longer be covered through the cost-based PPA. Similarly, BPA was required to take higher cost energy from the project until the PPA expired. For these reasons, PacifiCorp, EWEB, and BPA were all motivated to explore whether the existing Foote Creek I project could be unwound in order to achieve an outcome more favorable to customers as compared to continuing to operate the facility through its planned 30-year asset life. Repowering the facility presented the opportunity to realize this outcome for customers.

Q. What was necessary for the Company to repower the project?

A. Because of the very favorable wind conditions at the site, the Company was interested in repowering the facility so that customers could benefit from the low-cost energy that could be generated at the site with modern wind turbine equipment qualified at 100 percent of the value of the PTCs. To achieve that, however, it was necessary for the Company to acquire EWEB's ownership share of the facility and to terminate the existing PPA with BPA. The Company negotiated a PPA termination agreement with EWEB and BPA, and a purchase and sale agreement with EWEB for its interests in the facility. The termination of the PPA was negotiated to be effective upon

PacifiCorp's acquisition of EWEB's interest in the project. Closing of the purchase and sale agreement with EWEB was contingent upon the Company obtaining necessary regulatory and permitting approvals related to repowering, as well as satisfactory commercial arrangements for turbine supply and construction that ensured repowering could occur.

Q. How much did the Company pay EWEB for its interests in the facility?

A. PacifiCorp paid EWEB approximately [redacted] for its interests in the facility.

Q. Did the Company incur costs to terminate the Foote Creek I PPA with BPA?

A. No. Under the termination agreement, BPA paid an early termination payment for the facility in the amount of [redacted]—the Company's 78.79 percent ownership share of the facility—was paid to the Company. This payment to the Company and EWEB reflected the fact that BPA realizes savings by terminating the PPA early and replacing the power with lower cost energy resources.

Q. Were these amounts consistent with the Company's expectations?

A. Yes. These payments were consistent with the Company's economic analysis of the Foote Creek I repowering project, which is described by Mr. Link.

Q. Did the Company enter other commercial arrangements related to repowering at Foote Creek I?

A. Yes. The Company executed a turbine supply agreement with Vestas American Wind Technology, Inc. (Vestas) and executed a balance of plant construction contract with Thorstad Companies, Inc. Both contracts were awarded following competitive solicitation processes. When these contracts were finalized, the Company proceeded to close on the purchase of EWEB's interest in the project and terminate the PPA.

The Company also purchased the wind energy lease rights for the Foote Creek I facility.

Q. Why did the Company purchase the wind energy lease rights for Foote Creek I?

A. The Company was operating the Foote Creek I facility under land rights that were subleased from Chandar Energy Land Associates, Inc. (CELA), which held the master wind energy lease rights with the ultimate property owners upon whose land the Foote Creek I turbines are located. The wind energy lease payments due to CELA under the sublease were production-based and were costly as compared to what the Company pays for similar production-based wind energy leases, even given the high-value wind energy resource at the site. The Company was able to negotiate the purchase of the master wind energy leases from CELA at a cost that improved the economics of the Foote Creek I repowering project relative to continuing to operate under the existing sublease. Additionally, the master wind energy lease rights can be renewed for a total term of up to 99 years, providing potential future customer benefits even beyond the asset life of the repowered Foote Creek I facility.

Q. Were there unique permitting requirements related to Foote Creek I as compared to the other repowering projects?

A. Yes. It was necessary for the Company to obtain a new Certificate of Public Convenience and Necessity from the Wyoming Public Service Commission related to repowering the facility, and a new Conditional Use Permit from Carbon County, Wyoming. The Company also had to obtain concurrence from the Bureau of Land Management (BLM) that repowering was consistent with the existing right of way grant from BLM for the facility, and the Company worked with the U.S. Fish and

Wildlife Service to review the locations of the new turbines on the existing project footprint to evaluate and minimize potential avian impacts associated with the new turbine layout.

Q. When did the Company finally approve repowering the Foote Creek I facility?

A. The Company approved repowering the facility on June 25, 2019. The Company then closed on the purchase of EWEB's interest in the facility on July 24, 2019, after commercial arrangements to repower the facility were finalized. Following approval of the repowering project, the Company was able to negotiate the purchase of the master wind leases and incorporated this change in the project scope. The Company subsequently closed on the purchase of the master wind energy lease rights from CELA on August 8, 2019.

Q. What repowering costs is the Company seeking to recover in this filing?

A. Given the Company's previous filings related to repowering its wind fleet,[5] in this proceeding, the Company is seeking cost recovery of and a determination of prudence for acquiring the wind energy lease rights and repowering the Foote Creek I wind facility.

Q. What benefits will customers realize from repowering Foote Creek I?

A. Repowering Foote Creek I re-qualifies the facility for PTCs, which are benefits that are passed through to customers in the Company's annual Transition Adjustment Mechanism filing. Additionally, repowering increases the amount of emissions-free energy produced from the repowered facility, as shown in Confidential Exhibit PAC/903. Further, by replacing older WTG equipment, which is subject to

[5] *See* Docket Nos. UE 352 and UE 369.

more failure and maintenance issues than newer equipment, repowering will reduce PacifiCorp's ongoing operating costs. Finally, repowering the wind facility with new WTG equipment will extend the useful life by 21 years, creating substantial energy and capacity benefits for customers in the future when this wind facility would otherwise have been retired from service.

V. REQUALIFICATION FOR PTCS

Q. How do wind facilities qualify for the PTC extension enacted in 2015?

A. On December 18, 2015, Congress enacted changes to the federal Internal Revenue Code extending the full value of the PTC for wind facilities that began construction in 2015 and 2016. The legislation also provided for a phase-out of the PTC over three years, reducing the PTC value by 20 percent for wind facilities beginning construction in 2017, 40 percent for wind facilities beginning construction in 2018, and 60 percent for wind facilities beginning construction in 2019. The Internal Revenue Service (IRS) has issued guidance that establishes a "safe harbor" for taxpayers to demonstrate the year a facility will be deemed to "begin construction," thereby setting the value of the PTC. If at least five percent of the total project costs were incurred in 2016, then the facility qualifies under the IRS safe harbor for the full value of the PTC, provided the taxpayer can demonstrate "continuous efforts" to complete construction. The IRS has issued additional guidance that establishes a safe harbor for satisfying this continuous-efforts standard. Under the continuous-efforts safe harbor, the wind facilities must be in service by the end of the fourth calendar year following the calendar year in which construction began. Thus, wind facilities that began construction in 2016 must be in service no later than December 31, 2020, to satisfy the continuous-efforts safe-harbor provisions. If the facilities are not placed in service by December 31, 2020, the projects must satisfy IRS requirements that continuous-efforts were expended to repower the facilities, which may be a more challenging standard to meet.

Q. What is the full value of the PTC for wind facilities?

A. For 2019, wind facilities that are qualified for the PTC will receive 2.5 cents per kilowatt-hour, or $25 per megawatt-hour. This PTC value is adjusted annually based upon an inflation index, and the PTC is available for energy produced during the 10-year period after the wind facility begins commercial operation.

Q. Does the Foote Creek I repowering project qualify for the full value of the PTC under these rules?

A. Yes. Consistent with IRS guidance, a facility owner can demonstrate that construction of a facility has begun in the year in which at least five percent of the applicable project costs are incurred. If wind turbine equipment is purchased and delivered in 2016, and the equipment comprises at least five percent of the applicable project costs, a PTC "safe harbor" is created for the wind facilities subsequently constructed. To meet this requirement, PacifiCorp executed safe harbor equipment purchases with General Electric International, Inc. (GE) and Vestas in December 2016, and took delivery of equipment with a value sufficient to give the Company the ability to repower its entire wind fleet and qualify the repowered wind facilities for 100 percent of the PTC value. For the Foote Creek I facility, PacifiCorp will use safe harbor equipment obtained from Berkshire Hathaway Energy Renewables, a Berkshire Hathaway Energy affiliate, which similarly made safe harbor equipment purchases from Vestas in December 2016 that can be used to qualify the Foote Creek I project for 100 percent of the PTC value.

Q. What other requirements must repowered projects satisfy to qualify for the PTCs?

A. On May 5, 2016, the IRS issued Notice 2016-31 (Notice), which provides guidance on various aspects of qualifying for the PTCs and whether new tax credits can be claimed when wind turbines are repowered or retrofitted. The Notice generally provides that the repowering costs must equal at least four times the fair market value of the equipment that the owner retains from the original facility for the repowered turbines to qualify for new PTCs. Thus, 80 percent of the fair market value of the repowered WTG must result from repowering project costs while the value of the retained components cannot exceed 20 percent of the fair market value of the new facility. This “80/20” test is applied on a turbine-by-turbine basis. Each wind turbine—composed of a foundation, tower, and machine head (including nacelle, hub and rotor)—is considered a separate facility.

Q. Is the Foote Creek I facility subject to this 80/20 test?

A. No. Because the Foote Creek I facility will be repowered without using any retained components—meaning the tower and foundations of the existing turbines at the site will not be reused—the 80/20 test does not apply to this repowered facility. Thought of another way, the applicable repowering costs at Foote Creek I, on a per-turbine basis, will equal 100 percent of the repowering costs at this facility since there are no retained components, satisfying the 80/20 test.

Q. Have recent changes to federal tax laws impacted the ability to qualify the repowered Foote Creek I facility for PTCs?

A. No. Neither the Tax Cuts and Jobs Act enacted into law in December 2017 nor the Tax Extender and Disaster Relief Act of 2019 change the qualification requirements that allow Foote Creek I to receive the full value of PTCs.

VI. INCREASED ENERGY BENEFITS FOLLOWING REPOWERING

Q. Once repowered, how do the energy benefits of the Foote Creek I wind facility increase?

A. Repowering the Foote Creek I facility will employ entirely new wind turbines with new foundations and taller towers. The new nacelles have generators that have a much greater nameplate generating capacity than the equipment that is removed. The new turbines installed at the site will have generator nameplate ratings of 2.0 MW and 4.2 MW, replacing existing turbines with a 0.6 MW nameplate rating. Details regarding the proposed wind turbine upgrades, capital project costs, in-service date, and resulting energy benefits are shown in Confidential Exhibit PAC/903.

In addition to the larger generators in the repowered turbines, the new turbines also include larger blades, which will increase the rotor-swept area of the wind turbines. A larger rotor-swept area allows more of the wind energy flowing past the wind turbine to be captured and converted by the wind turbine into electricity. Because the size of the rotors will increase, the repowered turbines will also include more robust hubs, main shafts, bearings and couplings, and gearboxes suitable to handle the greater torque exerted by the larger rotors.

Finally, the Foote Creek I repowering project will result in all of the facility's output serving the Company's customers as compared to only approximately 47 percent under the earlier co-ownership and PPA structure. With the entire output of Foote Creek I directed to the Company's customers, and with the increased generation from the more efficient turbines, the amount of emissions-free energy provided to customers by the facility will increase by more than [redacted] percent.

Q. Will the larger blades installed with repowering increase the potential for avian impacts at the wind facilities?

A. Not necessarily. Although the larger blades will increase the overall risk zone (rotor-swept area) of the repowered wind turbines, this does not necessarily correlate with an increased risk of avian impacts at existing turbine sites. PacifiCorp performs monthly monitoring at all of its wind facilities and reports all findings to state wildlife agencies and the U.S. Fish and Wildlife Service. PacifiCorp will continue this monthly monitoring to determine if the new turbine blades cause additional impacts to avian species and will engage with the appropriate agency to discuss and, if prudent and practicable, implement additional avoidance, minimization, or mitigation measures.

Q. Are there other ways that the Company has worked to minimize avian impacts?

A. Yes. At the Foote Creek I facility, the significant reduction in the number of turbines required with site repowering means that less of the overall project site area will be covered by wind turbines. This has allowed the Company to adjust the layout of the wind turbines at the project site to avoid areas of higher avian use such as the edges of Foote Creek Rim.

Q. How did PacifiCorp determine the amount of additional generation that will be produced from the repowered Foote Creek I facility?

A. PacifiCorp's consultant, Black & Veatch (B&V) evaluated historical project generation and availability data from the existing Foote Creek I turbines, local and project-specific meteorological information, and the new proposed turbine layout to model the anticipated energy output of the repowered wind project, similar to the approach used by the Company to estimate the energy output from its new wind projects now under construction.

Q. Why was this approach most suitable for Foote Creek I?

A. This approach was most suitable because the turbine locations are changing at Foote Creek I, as discussed above, and also because the turbine hub heights are increasing from 40 meters to 80 meters. Thus, the wind conditions—wind speeds, turbulence intensity, and inflow angle to the wind turbines—experienced by the existing turbines may not be representative of what the new turbines will experience and therefore wind modeling was relied upon to develop the energy estimate for Foote Creek I.

Based on B&V's analysis, PacifiCorp estimates that energy production following repowering will increase at Foote Creek I as shown in Confidential Exhibit PAC/903.

Q. What are the major power production advantages of the new equipment?

A. The larger rotor size and improvements in blade design of the new equipment generate more power at all ranges of wind speeds. Additionally, the new turbines begin producing power at a lower wind speed than the existing equipment; thus, the turbines can produce energy during lower wind conditions in which the current equipment may sit idle. Additionally, the new 4.2 MW capacity wind turbines have a higher cut-out wind speed than the existing turbines, meaning they can continue producing power at higher wind speeds in which the existing equipment at the site would shut down. Because the new turbines will have an increased generator capacity, the turbines will also produce more energy when wind speeds are high and the turbines are at their maximum output, allowing the facility to produce equivalent capacity with far fewer turbines.

VII. REDUCED ONGOING OPERATIONAL COSTS FOLLOWING REPOWERING

Q. Aside from increased generation and the associated PTC benefits, what other benefits will be realized with the Foote Creek I repowering project?

A. The repowering project will lower the ongoing capital costs of operating the existing wind facility. PacifiCorp's turbine-supply contracts for repowering, consistent with wind industry standards for new equipment, will include a two-year warranty on the new equipment. This will reduce capital costs associated with replacing or refurbishing turbine components currently in service.

The repowering project will also result in more certainty related to ongoing operations and maintenance costs of the facility. PacifiCorp will operate the repowered facility under a full service agreement with the turbine equipment supplier who will be responsible for operating and maintaining the new turbines for a fixed cost while attaining a guaranteed availability of the turbines. Under this agreement, failure to meet the guaranteed availability, if not the result of an excusable event defined in the contract, will result in the payment of liquidated damages to the

Company. Customers will benefit by having operations and maintenance costs fixed for the term of the agreement. Thus, there is greater cost certainty related to the run-rate capital expenditures and operations and maintenance costs.

Q. Will the new equipment address any other operational issues?

A. Yes. Gearboxes at the Foote Creek I facility have experienced high failure rates relative to other gearboxes in the wind fleet. However, the impact to the Company of these failures has been mitigated by an agreement that was set to expire in 2024, at which point the cost of addressing failed gearboxes would be borne entirely by the Company and EWEB. Given the short remaining life of the project in 2024—with just five years of operational life remaining—turbines that experienced a failed gearbox after that time could not be economically returned to service given the limited remaining generation anticipated from the existing turbines and the estimated cost to replace a failed gearbox. Thus, repowering also addresses the likelihood of diminished generation from the Foote Creek I facility after 2024.

Q. What is the current asset life of the Foote Creek I wind facility?

A. All of the Company's existing wind facilities are currently being depreciated assuming a 30-year asset life. Given the 1999 commercial operation date of Foote Creek I, the depreciable life approved by the Commission for Foote Creek I extends to 2029. In anticipation of repowering the facility, the Company has proposed in the 2018 depreciation study in docket UM 1968 a new 30-year depreciable life following repowering that would extend the asset life of Foote Creek I by 21 years to 2050.

VIII. PROJECT PERMITTING, CONTRACTS, AND CONSTRUCTION STATUS

Q. What is the status of permitting related to the Foote Creek I repowering project?

A. PacifiCorp received approval from the Federal Aviation Administration for the new turbine locations in April 2018, indicating the new turbines location and heights would not pose a hazard to air navigation. Carbon County, Wyoming issued a new Conditional Use Permit for the repowered project in April 2019. The BLM, upon whose land approximately half of the turbines at the site are located, accepted the Company's revised plan of development for the project in June 2019, reflecting the repowered project.

Q. What is the status of contracting related to the Foote Creek I repowering project?

A. In July 2019, PacifiCorp executed contracts with Vestas for turbine supply and service and maintenance of the new turbines that will be installed at the site. Shortly thereafter, also in July 2019, PacifiCorp executed a construction contract with Thorstad Companies, Inc. for construction of the project.

Q. Has construction commenced on the Foote Creek I repowering project?

A. Yes. Initial site work began in the fall of 2019 with the installation of construction trailers, foundation excavation, and material deliveries. Site work has been halted for the winter and will resume when weather conditions allow. Turbine component manufacturing is currently underway, with turbine deliveries anticipated to begin in July 2020.

Q. When does the Company anticipate that Foote Creek I will enter commercial operation?

A. Commercial operation of the repowered Foote Creek I facility is anticipated to occur by December 1, 2020.

IX. DISPOSITION OF REPLACED EQUIPMENT

Q. What is PacifiCorp planning to do with the existing equipment that will be removed from Foote Creek I?

A. PacifiCorp issued a request for proposals related to the disposition of the existing equipment in which the Company sought proposals for the purchase or removal of the equipment that will be replaced as part of repowering. In general, proposals received from this solicitation were not favorable as compared to the equipment removal proposals offered by the construction contractor that will be installing the new equipment.

PacifiCorp understands that a significant number of turbines of all makes and models are currently being repowered, and will likely continue to be before the sunset of the PTCs available for wind energy projects in 2024. As a result, there is very little market for used turbines and the salvage value of the equipment is very low given the large number of repowered turbines and associated spare parts that have become available as a result of the significant repowering effort that the wind industry is now undertaking. While some individual turbine sales are likely to result from PacifiCorp's efforts to obtain the highest salvage value from the removed equipment at other repowered projects, the lowest cost alternative for the disposition of the old equipment is to allow the construction contractors to retain the equipment so the scrap value offsets their equipment removal, handling, and transportation costs. That is also the case at Foote Creek I. Given the relative inefficiency of the replaced equipment compared to new equipment, it does not make economic sense to redeploy the replaced equipment at other potential wind sites.

Q. Does the Company's inability to achieve a salvage value for the replaced equipment impact the Company's economic analysis of the Foote Creek I repowering project?

A. No. PacifiCorp did not assume any salvage value for the replaced equipment in its economic analysis. Thus, project economics are not impacted by the fact that none of the old equipment will ultimately be re-sold by the Company when it is removed.

Q. Does PacifiCorp have a proposal for the treatment of the remaining net book value of the replaced equipment at Foote Creek I?

A. Yes. Consistent with the stipulation filed in docket UE 369, PacifiCorp proposes to offset the remaining net book value of the replaced wind equipment with the deferred Open Access Transmission Tariff revenues. This treatment is described more fully in the direct testimony of Ms. Shelley E. McCoy.

X. OVERVIEW OF LEWIS RIVER HYDROELCTRIC PROJECTS MERWIN FISH COLLECTION AND SORTING FACILITY

Q. Please provide a brief description of the Company's Lewis River hydroelectric projects.

A. The Company owns and operates approximately 1,074 MW of hydroelectric power generation facilities in the Pacific Northwest and Rocky Mountains that provide carbon free electricity for the benefit of our customers. The Merwin, Yale, and Swift

No. 1 Hydroelectric Projects (collectively, the Lewis River Projects), are located in Southwest Washington and comprise the Company's largest hydroelectric project with a generating capacity of 510 MW. The Lewis River Projects are multi-value resources that provide low-cost, emissions-free energy for customers, allow for load following to meet dynamic customer and system balancing needs, assist in integrating variable, renewable generation resources, and provide recreation opportunities on project reservoirs and associated lands. These hydroelectric resources also provide spinning reserves and voltage support to the transmission system, and participate in the Energy Imbalance Market, which provides benefits to customers by reducing system balancing costs.

Q. What is the driver for the Merwin Fish Collection and Sorting Facility project at the Lewis River Projects that the Company has included in its filing?

A. On June 26, 2008, FERC issued new 50-year licenses for the Lewis River Projects, which include the Merwin (FERC Project No. 935), Yale (FERC Project No. 2071), and Swift No. 1 (FERC Project No. 2111) Hydroelectric Projects. The licenses incorporate the provisions of the comprehensive multi-party Lewis River Settlement Agreement (Settlement Agreement) entered into by the Company in 2004 with federal and state agencies, local governments, local Tribal governments, non-governmental entities, and conservation groups.

The overall objective of the Settlement Agreement was to outline agreed-upon measures to protect and enhance fish, wildlife, and other ecological resources affected by the Lewis River Projects while providing for the continued operation of the facilities for the benefit of customers and providing other public benefits, including flood control and recreation. To address the fish and wildlife impacts of the Lewis River Projects, key components of the Settlement Agreement include the construction of fish passage facilities and fish hatchery modifications. FERC incorporated these requirements into the licenses for the Lewis River Projects as license articles, or as mandatory conditions under Section 4(e) or Section 18 of the Federal Power Act, or these requirements were included as terms and conditions of the Biological Opinions issued by the National Marine Fisheries Service and the U.S. Fish and Wildlife Service for the relicensing of the Lewis River Projects.

Q. What is the status of the Company's implementation of these fish passage and hatchery requirements?

A. To date, the Company has constructed fish passage facilities that allow fish to access the upper Lewis River basin. This area contains the majority of historic habitat that was made inaccessible to anadromous fish as a result of construction of the Lewis River Projects between 1931 and 1958. The new fish passage facilities, along with completed fish hatchery modifications projects, support the first phase of fish mitigation and enhancement projects contemplated in the Settlement Agreement.

Q. Please describe how fish passage facilities have restored fish access to historic habitat areas on the Lewis River impacted by the hydroelectric projects.

A. The restored access has been achieved by means of a trap-and-haul fish passage program that collects adult salmon and steelhead from the most downstream development—Merwin Dam—and transports those fish upstream of Swift Dam. The collection of the upstream-migrating adults is accomplished at the Merwin Fish Collection and Sorting Facility. The juvenile progeny of adult fish transported upstream of Swift Dam are collected from Swift Reservoir at the Swift Floating Surface Collector, and then transported downstream of Merwin Dam. Before release into the lower Lewis River, fish are placed into the Woodland Release Ponds for a short period to observe the condition of the fish and enumerate any mortalities to track the effectiveness of the program. These facilities are the major components of the Lewis River Fish Passage Program.

Q. Please describe the Merwin Fish Collection and Sorting Facility.

A. The Merwin Fish Collection and Sorting Facility is the key component of the upstream fish passage system of the Lewis River Fish Passage Program and is designed to collect, trap, and transport adult anadromous fish around the three Lewis River dams so they can access and spawn in upstream habitat areas. The facility consists of four major components; a fish attraction water supply system, a fish ladder, a fish crowder and lift, and a fish sorting building with holding tanks. Fish are attracted to the ladder by water provided from the fish attraction water system, ascend the ladder, and are transported to the sorting area via the crowder and fish lift. Once inside the fish sorting building, biologists enumerate and sort the fish by species. Once sorted, fish are sent to holding tanks prior to transport in large capacity fish trucks to their final destination upstream of Swift dam. The facility operates 24 hours per day, 365 days per year. The facility cost approximately $49.6 million and was placed in service in December 2013.

Q. Was construction of the Merwin Fish Collection and Sorting Facility mandated by FERC?

A. Yes. Construction of the facility was mandated by the Settlement Agreement which was incorporated into the FERC licenses for the Lewis River Projects through license articles or mandatory conditioning authority under the Federal Power Act.[6]

Q. Was the project subject to review and approval by resource agencies?

A. Yes. Consistent with the requirements of the FERC licenses, the Company engaged in project siting and design reviews with affected agencies, Tribes, and other stakeholders, including the National Marine Fisheries Service, the U.S. Fish and Wildlife Service, the Washington Department of Fish and Wildlife, and the U.S. Forest Service. All required, federal, state, and local permits and approvals were acquired for physical construction of the project.

XI. CONCLUSION

Q. Please summarize your recommendations.

A. I recommend that the Commission determine that the Foote Creek I repowering project and the Merwin Fish Collection and Sorting Facility project provide benefits to Oregon customers and are therefore prudent and in the public interest.

Q. Does this conclude your direct testimony?

A. Yes.

[6] *See* PacifiCorp, 123 FERC ¶ 62,258 (2008), *Order on Reh'g*, 125 FERC ¶ 61,046 (2008).

Docket No. UE 374
Exhibit PAC/901
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

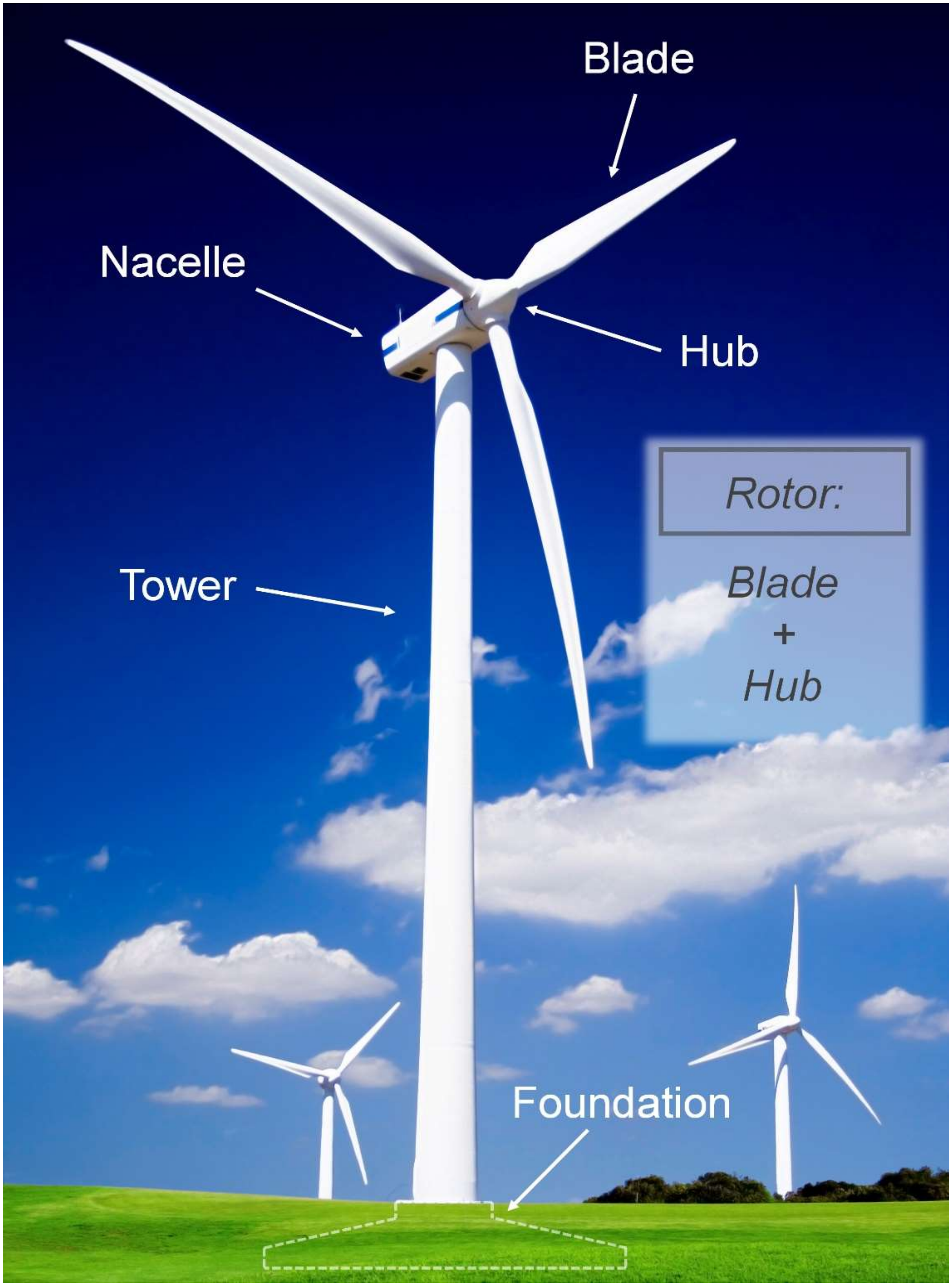
PACIFICORP

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Major Components of a Wind Turbine Generator

February 2020

Major Components of a Wind Turbine Generator



Docket No. UE 374
Exhibit PAC/902
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Foote Creek I Repowering Project

February 2020

PacifiCorp
Foote Creek I Wind Repowering Project

Project #	Wind Project	Location	Original Commercial Online Date	Years in Operation	Number of WTGs	Net Capacity (MW)	Retirement year without Repowering	Retirement year with Repowering	Additional Life (Years)
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Wyoming Projects									
1	Foote Creek I *	Arlington, WY	4/22/1999	20.8	68	40.8	2029	2050	21

Note:
* PacifiCorp owned 78.79% of the 40.8 MW Foote Creek I project (32.1 MW) prior to acquisition of the Eugene Water & Electic Board's 21.21% interest in the facility in July 2019 in order to repower the facility.

REDACTED
Docket No. UE 374
Exhibit PAC/903
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Foote Creek I Repowering Project Details, Capital Costs, and In-Service Date

February 2020

REDACTED

CONFIDENTIAL

PacifiCorp Foote Creek I Wind Repowering Project

Repowering Project Details, Capital Costs, and In-Service Dates

Project #	Wind Project	Existing WTGs	WTGs to be Repowered	Existing Project Capacity (MW)	Post-Repowering Capacity (MW)	Increased Deliverable Capacity (MW)	Repowering In-Service Date	Existing Generation (MWh)*	Estimated Generation Increase (%)	Incremental Energy (MWh)	Repowered Project Generation (MWh)	Capital Cost ($m)
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
1	Foote Creek I	68	13	40.8	41.4	0.6	12/1/2020	[redacted]				

* Average long-term generation from first full year of facility operation through 2016 (prior to repowering project).

Docket No. UE 374
Exhibit PAC/1000
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Richard A. Vail

February 2020

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ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp.

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

Q. Please describe your education and professional experience.

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

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to describe PacifiCorp's transmission system and the benefits it provides to Oregon customers. PacifiCorp's transmission system is designed to reliably transfer electric energy from a broad array of generation resources to load. PacifiCorp's interconnection to other balancing authority areas

(BAAs) and participation in the Energy Imbalance Market (EIM) provide access to markets and promote affordable and reliable service to PacifiCorp's customers. Further, all transmission system capacity increases provide benefits to customers by increasing reliability and allowing more generation to interconnect to serve customer load, as well as allowing PacifiCorp flexibility in designating generation resources for reserve capacity to comply with mandatory reliability standards.

I also specifically describe PacifiCorp's major capital investment projects for new distribution and transmission systems included in this rate case. These investments include the transmission projects associated with Energy Vision 2020 in addition to other transmission improvements. My testimony demonstrates that the Company has made prudent decisions related to these projects and that these investments result in an immediate benefit to PacifiCorp's customers in Oregon. I recommend that the Public Utility Commission of Oregon (Commission) find these investments prudent and in the public interest.

III. OVERVIEW OF PACIFICORP'S TRANSMISSION SYSTEM AND INVESTMENT DRIVERS

Q. Please briefly describe PacifiCorp's transmission system.

A. PacifiCorp owns and operates approximately 16,500 miles of transmission lines ranging from 46 kilovolts (kV) to 500 kV across multiple western states. PacifiCorp has nearly two million customers with approximately 615,000 customers located in Oregon.

For convenience in load and resource planning, PacifiCorp groups its local area transmission and distribution system into load areas. These load areas are regions in which the PacifiCorp system is generally contiguous within the load area, while a set of transmission constraints and boundaries separate the load area from other portions of the PacifiCorp system. In Oregon, PacifiCorp generally has three primary load areas: Southern Oregon, Central Oregon, and the Willamette Valley. These primary load areas are further divided into 23 sub-areas within Oregon for planning purposes when evaluating the capability of the PacifiCorp system to meet the load and resource requirements of its customers.

Q. Please describe PacifiCorp's responsibility for maintaining reliability on its transmission system.

A. In 1996, the Federal Energy Regulatory Commission (FERC) issued Order No. 888,[1] which required that transmission system owners provide non-discriminatory access to their transmission systems. PacifiCorp is obligated under its OATT to plan its transmission system for the open access of all transmission customers. Through the OATT Attachment K local planning process and the FERC Order 1000 regional and inter-regional planning processes, PacifiCorp participates in open stakeholder planning processes covering its entire transmission footprint. These planning processes result in system plans that incorporate economics, reliability, and public policy inputs and requirements. PacifiCorp must also coordinate with other entities in the region for transmission planning purposes as required under FERC Order No.

[1] *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).

1000.[2] In addition to these more general requirements, PacifiCorp also must comply with the specific requirements of the mandatory reliability standards approved by FERC.

Q. Who establishes transmission reliability standards?

A. FERC directs the North American Electric Reliability Corporation (NERC) to develop Reliability Standards to ensure the safe and reliable operation of the Bulk Electric System (BES) in the United States in a variety of operating conditions. On April 1, 2005, NERC established a set of transmission operations reliability standards. A subset of the transmission reliability standards are the transmission planning standards (TPL Standards). The purpose of the TPL Standards is to "establish Transmission system planning performance requirements within the planning horizon to develop a BES that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies."[3] The TPL Standards, along with regional planning criteria (*i.e.*, regional planning criteria established by the Western Electricity Coordinating Council (WECC)) and utility-specific planning criteria, define the minimum transmission system requirements to safely and reliably serve customers.

Q. How does PacifiCorp ensure compliance with the TPL Standards?

A. The Company plans, designs, and operates its transmission system to meet or exceed NERC Standards for BES and WECC regional standards and criteria. To ensure compliance with applicable TPL Standards, PacifiCorp conducts an annual system

[2] *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).
[3] *See* http://www.nerc.com/files/tpl-001-4.pdf.

assessment to evaluate the performance of the Company's transmission system and to identify system deficiencies. The annual system assessment is comprised of steady-state, stability, and short circuit analyses[4] to evaluate peak and off-peak load seasons in the near-term (one-, two-, and five-year) and long-term (10-year) planning horizons. The assessment is performed using power flow base cases maintained by WECC and developed in coordination among all transmission planning entities in the Western Interconnection. These base cases include load and resource forecasts along with planned transmission system changes for each of the future year cases and are intended to identify future system deficiencies to be mitigated.

As part of the annual system assessment, corrective action plans are developed to mitigate identified deficiencies, and may prescribe construction of transmission system reinforcement projects or, as applicable, adoption of new operating procedures. In certain instances, operating procedures prescribing action to change the configuration of the transmission system can prevent deficiencies from occurring when there are two back-to-back (N-1-1) (or concurrent) transmission system events. However, the use of operating procedure actions have limitations. In particular, actions taken in connection with operating procedures that are designed to protect the integrity of the larger integrated transmission system in the Western Interconnection of the United States can lead to large numbers of customers being at risk of an outage upon the occurrence of the second of two back-to-back (N-1-1) events. An effective

[4] 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.

corrective action plan is critical to ensuring system reliability so that large numbers of customers are not subjected to avoidable outage risk.

Q. Is compliance with the reliability standards optional?

A. No. The reliability standards are a federal requirement, subject to oversight and enforcement by WECC, NERC, and FERC. PacifiCorp is subject to compliance audits every three years, and may be required to prove compliance during other NERC or WECC reliability initiatives or investigations. Failure to comply with the reliability standards could expose the Company to penalties of up to $1 million per day, per violation. Accordingly, and as described more fully later in my testimony, compliance with reliability standards is a major driver for the new capital investments in PacifiCorp's system transmission assets identified in and supported by my testimony.

Q. Please identify other drivers that are relevant to the capital investments in PacifiCorp's distribution and transmission systems described in your testimony.

A. There are several other drivers that inform whether PacifiCorp will build new distribution and transmission facilities, including increased demand for transmission capacity, requests for transmission service, increased demand for distribution capacity, and the age and condition of existing distribution and transmission facilities. The specific drivers for the projects addressed in my testimony are described in more detail later in my testimony.

IV. OVERVIEW OF INVESTMENTS DESCRIBED IN TESTIMONY

Q. What specific distribution and transmission system investments are you addressing in your testimony?

A. My testimony addresses PacifiCorp's major new distribution and transmission system projects included in this general rate case filing. Specifically, my testimony addresses the following projects:

1. Aeolus to Bridger/Anticline 500 kV Transmission Project

The Aeolus to Bridger/Anticline 500 kV Transmission Project includes the construction of facilities to integrate approximately 1,150 megawatts (MW) of new wind generation resources located in southeast Wyoming (*i.e.*, TB Flats I and II, Cedar Springs, and Ekola Flats, collectively referred to as the Energy Vision 2020 Wind Projects or individually referred to as an Energy Vision 2020 Wind Project)[5] and deliver energy from those resources across PacifiCorp's system. Those facilities include:

- A 140-mile, 500 kV transmission line (Aeolus to Anticline line), which includes construction of the new Aeolus (500/230 kV) and Anticline (500/345 kV) substations; a map of the proposed line can be found attached in Exhibit PAC/1001;
- A five-mile, 345 kV transmission line that will extend from the proposed Anticline substation to the Jim Bridger substation, along with associated interconnection facilities at the Jim Bridger substation to accommodate the interconnection of the 345 kV line from the proposed Anticline substation; and
- A voltage control device at the existing Latham substation.

Additional network upgrades are also required to accommodate the Aeolus to Bridger/Anticline 500 kV Line Project and the interconnection of the Energy Vision 2020 Wind Projects (230 kV Network Upgrades). These network upgrades include:

[5] The Energy Vision 2020 Wind Projects are more thoroughly discussed in the testimony of Mr. Chad A. Teply.

- A new 16-mile 230 kV transmission line parallel to an existing 230 kV line from the Shirley Basin substation to the proposed Aeolus substation, including modifications to the Shirley Basin substation to accommodate the new line;
- The reconstruction of four miles of an existing 230 kV transmission line between the proposed Aeolus substation and the Freezeout substation, including modifications of the Freezeout substation to accommodate the new line; and
- The reconstruction of 14 miles of an existing 230 kV transmission line between the Freezeout substation and the Standpipe substation, including modifications to the Freezeout and Standpipe substations to accommodate the transmission lines.

The reconstructed sections are proposed to be in a parallel alignment to the existing 230 kV transmission lines. The Aeolus to Bridger/Anticline 500 kV Transmission Project and 230 kV Network Upgrades are needed to support interconnection of the new Energy Vision 2020 Wind Projects, which are described in the testimony of Mr. Chad A. Teply.

2. Wallula to McNary 230 kV New Transmission Line Project

The Wallula to McNary 230 kV new transmission line extending from Wallula substation located in Wallula, Washington, to McNary substation located near Umatilla, Oregon, as shown in the map attached in Exhibit PAC/1002.

3. Snow Goose 500/230 kV New Substation Project

The Snow Goose 500/230 kV substation which is located near Klamath Falls, Oregon, as shown in the map attached in Exhibit PAC/1003.

4. Vantage to Pomona Heights 230 kV Transmission Line Project

The Vantage to Pomona Heights 230 kV new transmission line extending from Vantage substation located northeast of Yakima, Washington, to Pomona Heights substation located in Selah, Washington, as shown in the map attached in Exhibit PAC/1004.

5. Goshen to Sugarmill to Rigby 161 kV Transmission Line Project

The Goshen to Sugarmill to Rigby 161 kV transmission line rebuild of an existing 69 kV line from Goshen substation to Sugarmill substation and then construction of a new 161 kV line from Sugarmill substation to Rigby substation located in the southeast Idaho area, as shown in the map attached in Exhibit PAC/1005.

6. Sigurd to Red Butte 345kV Transmission Line Project

The Sigurd to Red Butte 345 kV transmission line project constructed a new single circuit 345 kV transmission line between Sigurd substation in Sevier County, Utah and Red Butte substation in Washington County, Utah, as shown in the map attached in Exhibit PAC/1006. The project also included substation and control system upgrades and modifications at both Sigurd and Red Butte substations.

7. Northeast (NE) Portland Transmission Upgrade Project

The NE Portland Transmission Upgrade project consisted of five major construction components, which included: converting Parkrose substation from 57 kV to 115 kV; re-insulating sections of transmission lines to 115 kV; converting Columbia substation 57 kV to 69 kV; converting Vernon substation from 69 kV to 115 kV; and installing two substation transformers and voltage regulators at Albina substation. The project is located in Portland, Oregon, and shown in Exhibit PAC/1007.

8. Southwest Wyoming Silver Creek 138kV Transmission Line Project

This project sited, permitted, and rebuilt approximately 70 miles of 46 kV transmission line at 138 kV, built a new 138/46/12.5 kV substation (near Henefer, Utah), removed the Henefer substation, and converted Coalville substation to 138 kV. A project map and subsequent scope change diagram are included in Exhibit PAC/1008.

9. Threemile Canyon Farm Project

This project added a fourth 230-34.5 kV, 25 megavolt-ampere (MVA) transformer and a third 34.5 kV feeder position at the existing Dalreed substation and upgrades to the local 34.5 kV and 4.16 kV distribution system located near Boardman, Oregon, as shown on the map attached in Exhibit PAC/1009.

Q. What are the projected costs associated with these distribution and transmission investments and their associated in-service dates?

A. Table 1 identifies the specific projects and associated costs and in-service dates.

TABLE 1

Project	Total Company Cost ($m)	In-Service Date
Aeolus to Bridger/Anticline 500 kV line[6]		
Sequence Two (In-Service)	$4.1	July 2018
Sequence Three	$11.1	December 2019
Sequence Four	$663.9	December 2020
Q707 TB Flats 1	$30.6	December 2020
Q712 Cedar Springs Wind 1	$61.7	December 2020
Wallula to McNary 230 kV New Transmission Line		
Sequence One (In-Service)	$6.4	December 2017
Sequence Two (In-Service)	$36.2	January 2019
Snow Goose 500-230 kV New Substation Project		
Sequence One (In-Service)	$10.3	May 2017
Sequence Two (In-Service)	$32.5	November 2017
Vantage to Pomona Heights 230 kV New Transmission Line Project	$57.3	May 2020
Goshen-Sugarmill-Rigby 161kV Transmission Line Project		
Sequence One	$21.5	November 2020
Sequence Two (not included in this case)	N/A	November 2022
Sigurd-Red Butte 345kV Line		
Sequence One (In-Service)	$2.2m	May 2013
Sequence Two (In-Service	$349.0m	May 2015
Sequence Four (In-Service)	$3.4m	June 2017
NE Portland Transmission Upgrade	$20.6	December 2018
Sequence One- (In-Service)	$8.4m	December 2016
Sequence Two- (In-Service)	$.8m	December 2016
Sequence Three- (In-Service)	$3.9	December 2018
Sequence Four- (In-Service)	$1.0m	December 2018
Sequence Five- (In-Service)	$4.9m	December 2018
Sequence Six- (In-Service)	$1.6m	May 2019
Southwest WY Silver Creek 138kV Ln- (In-Service)	$41.9m	August 2017
Threemile Canyon Farm 2,500 HP Increase- (In-Service)	$6.2m	April 2015

These amounts include costs associated with engineering, project management, materials and equipment, construction, right-of-way (including rights

[6] As discussed later in my testimony, Sequence One was placed into service in 2011.

acquired by condemnation), and an allowance for funds used during construction. These costs are also shown in the testimony and exhibits of Ms. Shelley E. McCoy. The in-service dates are based on the best available information at the time of preparing this case.

Q. Please briefly describe the benefits associated with these investments.

A. The benefits associated with these investments include increased load serving capability, enhanced reliability, conformance with NERC Reliability Standards, improved transfer capability within the existing system, relief of existing congestion, and interconnection and integration of new wind resources into PacifiCorp's transmission system. These benefits will be described more fully below.

Q. Will PacifiCorp's OATT transmission customers pay for some of these assets?

A. Yes, through OATT transmission charges. The Company's current transmission formula rate (included in PacifiCorp's OATT) was approved by FERC in Docket No. ER11-3643.[7] The Company's transmission formula rate is updated annually with the annual transmission revenue requirement (ATRR) that represents the annual total cost of providing firm transmission service over the test year. The ATRR calculation incorporates all transmission system investments by the Company, a return on rate base, income taxes, expenses, and certain revenue credits, among other specific elements and adjustments. Transmission assets, including new transmission capital, are included in the ATRR, weighted by months in service. The ATRR is converted into a rate by dividing the ATRR by firm transmission demand. All third-party revenues for transmission service (along with third-party revenues for ancillary

[7] *In re PacifiCorp*, 143 FERC ¶ 61,162 (May 23, 2013) (letter order approving settlement agreement establishing formula rate).

services) are included as revenue credits in the calculation of rates in each of the Company's state retail jurisdictions.

Q. Please explain how network upgrade cost allocation works under the OATT.

A. In accordance with its OATT, when PacifiCorp receives a request for generation interconnection or transmission service, the Company completes studies to determine what new facilities or upgrades to existing facilities are required to accommodate the request. The studies identify the facilities and upgrades required and classify the asset additions required to support the service into two categories: direct assigned or network upgrade. Direct assigned assets are those assets that only benefit or are used solely by the customer requesting generator interconnection or transmission service. Those costs are directly assigned and paid for by that customer and will not be included in either the Company's ATRR or retail rate base. Network upgrades, on the other hand, are those assets that benefit all customers using the transmission system. Costs associated with network upgrades are investments by the transmission provider and are included in PacifiCorp's ATRR[8] and retail rate base.

V. AEOLUS TO BRIDGER/ANTICLINE 500 KV TRANSMISSION PROJECT

Q. Please describe the investment for the Aeolus to Bridger/Anticline 500 kV Transmission Project.

A. The Aeolus to Bridger/Anticline 500 kV Transmission Project is planned to be placed in-service in four sequences. The first sequence was the purchase of property used

[8] 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); *see also* Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003-B, 109 FERC ¶ 61,287 (Dec. 20, 2004).

for the new Aeolus and Anticline substations, which were placed in-service in March 2011. The second sequence was to construct a replacement access bridge over the Medicine Bow River and complete associated upgrades to an existing unpaved county road for $4.1 million in July 2018. The third sequence of work started in December 2019, for an estimated $11.1 million, is the installation of a Static Synchronous Compensator (STATCOM) voltage control device. To accommodate this equipment, the Latham Substation will be expanded with a new line termination bay. Finally, the last sequence of plant in-service is the two 500 kV substations and the transmission line for $663.9 million in December 2020.

Q. Please describe the 230 kV Network Upgrades.

A. There are four generation interconnection projects selected as part of a request for proposal to interconnect 1,150 MW of new wind generation to the 230 kV transmission system in eastern Wyoming. The request for proposal process and the resulting resources selected are described in the testimony of Mr. Rick T. Link. A separate generation interconnection agreement was negotiated and signed for each of the four projects.

Q707 TB Flats 1 is planned to be placed in-service in December 2020 and requires $30.6 million of network upgrades. This project includes a new 16-mile 230 kV transmission line parallel to an existing 230 kV line from Shirley Basin substation to the proposed Aeolus substation, including modifications to the existing Shirley Basin substation.

Q712 Cedar Springs Wind 1 is planned to go into service in December 2020 and requires $61.7 million of network upgrades. This project includes the reconstruction of four miles of an existing 230 kV transmission line between the proposed Aeolus substation and the Freezeout substation, including modifications as required at the Freezeout substation; the reconstruction of 14 miles of an existing 230 kV transmission line between the Freezeout substation and the Standpipe substation, including modifications as required at the Freezeout and Standpipe substations; and the reconstruction of 16 miles of an existing 230 kV transmission line from the proposed Aeolus substation to the existing Shirley Basin substation.

Q. Please explain why this investment in the Aeolus to Bridger/Anticline 500kV Transmission Project was needed.

A. As described in more detail in the testimony of Mr. Link, the Aeolus to Bridger/Anticline 500 kV Transmission Project supports the Company's short- and long-term energy demands for serving customers across the entire PacifiCorp system, and will strengthen the overall reliability of the existing Wyoming transmission system and therefore PacifiCorp's entire transmission system.

The Aeolus to Bridger/Anticline 500 kV Transmission Project has long been recognized as an integral component of PacifiCorp's long-term transmission planning, but the construction of the project has not been economic until now. The renewal of the federal wind production tax credits (PTCs) created a unique opportunity for the Company to acquire significant cost-effective, zero emission wind resources, generating PTCs that provide cost savings necessary to economically construct the project. To achieve the full customer benefits of the PTCs, however, the Company must develop the Energy Vision 2020 Wind Projects and the Aeolus to

Bridger/Anticline 500 kV Transmission Project together and bring them into service by December 31, 2020.

Q. Can PacifiCorp develop the Energy Vision 2020 Wind Projects without the Aeolus to Bridger/Anticline 500 kV Transmission Project?

A. No. The Energy Vision 2020 Wind Projects are not economic without the completion of the Aeolus to Bridger/Anticline 500 kV Transmission Project, which is needed to relieve existing congestion and to interconnect and integrate new PTC-eligible wind resources in high-wind areas of Wyoming. Similarly, the Aeolus to Bridger/Anticline 500 kV Transmission Project is not economic to PacifiCorp customers if there are no incremental cost-effective wind resources producing PTCs.

Q. How will the Aeolus to Bridger/Anticline 500 kV Transmission Project benefit customers and improve system performance?

A. The Aeolus to Bridger/Anticline 500 kV Transmission Project will: (1) relieve congestion and increase transmission capacity across Wyoming, allowing interconnection and integration of new generation resources and more efficient dispatch of and greater flexibility managing existing resources; (2) provide critical voltage support to the transmission system; (3) improve system reliability; and (4) reduce energy and capacity losses. Remarkably, customers will be able to receive all of these benefits, while taking advantage of the PTCs from the Energy Vision 2020 Wind Projects to offset the costs of the project.

Q. How will the Aeolus to Bridger/Anticline 500 kV Transmission Project increase transmission capacity in southeastern Wyoming?

A. Currently, the Company's transmission system in southeastern Wyoming is operating at capacity, which limits transfer of existing resources from eastern Wyoming and precludes the ability to interconnect and integrate additional resources east of Bridger/Anticline. This investment will increase the transfer capability from east to west across Wyoming by 951 MW. When the Aeolus to Bridger/Anticline 500 kV Transmission Project is complete, the Company estimates that it will be able to accommodate up to approximately 1,510 MW of additional new wind resources east of the Bridger/Anticline substation.

The increased transmission capacity also provides improved access to existing generation resources, and will provide options to access other resources, including renewable resources. The resulting increase in capacity allows flexibility to use future generation and interconnected transmission facilities.

Q. How will the Aeolus to Bridger/Anticline 500 kV Transmission Project impact the dispatch of the Company's existing generation resources?

A. The Aeolus to Bridger/Anticline 500 kV Transmission Project will increase the ability to dispatch the Company's existing resources. With the project being constructed between eastern Wyoming and Jim Bridger/Anticline, eastern Wyoming transmission congestion will be mitigated and wind resources entering the Jim Bridger energy hub can flow onto the Bridger West transmission path to PacifiCorp load centers. With increased wind generation entering the Jim Bridger energy hub, the Jim Bridger generating plant can be dispatched to maximize wind transfers out of the energy hub.

Q. Will the increased capacity benefit customers in any other ways?

A Yes. To provide low-cost energy, the Company must have the ability to acquire power from numerous generation sources and negotiate the most competitive pricing. By adding transmission capacity, the Company has increased its ability and options to obtain additional generation sources at competitive pricing. The Aeolus to Bridger/Anticline 500 kV Transmission Project will result in a stronger transmission system in southern Wyoming and therefore throughout PacifiCorp's entire service territory.

Q. Is the increased capacity provided by the Aeolus to Bridger/Anticline 500 kV Transmission Project consistent with the Company's obligation to provide transmission service under its OATT?

A. Yes. The Company's OATT, approved by FERC, details the Company's requirements and obligations to provide transmission service. Section 28.2 of the OATT defines the Company's responsibilities, which include the requirement to "plan, construct, operate, and maintain the system in accordance with good utility practice." Section 28.3 states the requirement for the Company to provide "firm service over the system so that designated resources can be delivered to designated loads." The Company is required to provide adequate and non-discriminatory service to all network customers. Although the Aeolus to Bridger/Anticline 500 kV Transmission Project is not specifically mandated by the Company's obligations under its OATT, the project will allow the Company to more efficiently meet current and forecasted customer energy demand by relieving the existing transmission congestion in southeastern Wyoming.

Q. What are the benefits resulting from the critical voltage support that will be provided by the Aeolus to Bridger/Anticline 500 kV Transmission Project?

A. Under certain operating conditions, voltage control issues have limited the ability to add additional resources, particularly wind resources, in southeastern Wyoming. The Aeolus to Bridger/Anticline 500 kV Transmission Project will greatly enhance the ability to control voltage issues and allow additional wind generation to be integrated into the Company's system.

Q. How will the Aeolus to Bridger/Anticline 500 kV Transmission Project improve system reliability?

A. The transmission grid can be affected in its entirety by what happens on an individual transmission line or path. For example, the transmission system between eastern and central Wyoming is comprised of several individual transmission lines or line segments. A single outage on any of the individual lines or line segments due to storm, fire, or other external human interference can and does cause significant reductions in transfer capability, which can negatively impact the Company's ability to serve customers. Line outages require the Company to curtail generation resources to stabilize system voltages and require less efficient re-dispatch of system resources to meet network load requirements. This in turn places a burden across the entire interconnected system as generation resources across PacifiCorp's service territory, using PacifiCorp's transmission system, are used to ensure the continued reliability of energy supply to all PacifiCorp customers.

In the event of a line outage, the redundancy provided by the Aeolus to Bridger/Anticline 500 kV Transmission Project will allow the Company to continue to meet native load obligations and other contractual obligations to third parties. Strengthening this path and increasing system redundancy will benefit all customers by reducing the risk of outages and inefficient dispatch resulting from those outages.

In addition, the Aeolus to Bridger/Anticline 500 kV Transmission Project will improve the Company's ability to perform required maintenance without significant operational impacts to the system, and will reduce impacts to customers during planned and forced system outages. Transmission line and substation maintenance windows are currently limited because the system is highly utilized. By relieving congestion and providing additional transmission paths, this investment will allow greater flexibility to the Company in the operation of its transmission system.

Q. Can you provide an example where the Aeolus to Bridger/Anticline 500 kV Transmission Project would mitigate the impact of an outage on the 230 kV transmission system?

A. Yes. For an outage of the Latham – Point of Rocks 230 kV line, the Aeolus to Bridger/Anticline 500 kV Transmission Project eliminates the overload on the Dave Johnston to Amasa 230 kV line. For an outage of the Mustang to Spence 230 kV line, the Aeolus to Bridger/Anticline 500 kV Transmission Project eliminates the overload on 230 kV lines west of Platte. For an outage of the Riverton to Wyopo 230 kV line, the Aeolus to Bridger/Anticline 500 kV Transmission Project eliminates overloads on 230 kV lines west of Platte. For an outage of the Dave Johnston to Amasa 230 kV line, the Aeolus to Bridger/Anticline 500 kV Transmission Project eliminates the overload on the 230 kV lines west of Platte. For an outage of the Platte to Standpipe

230 kV line, the Aeolus to Bridger/Anticline 500 kV Transmission Project will eliminate the need to trip approximately 130 MW of wind generation at Foote Creek.

Q. Will the Aeolus to Bridger/Anticline 500 kV Transmission Project also enhance the Company's ability to meet the reliability standards applicable to its transmission system?

A. Yes. Although the Company currently meets or exceeds the applicable reliability standards and criteria for its transmission system, the addition of the Aeolus to Bridger/Anticline 500 kV Transmission Project will allow the Company to do this more efficiently.

Q. How do NERC and WECC standards and criteria influence the need for the Aeolus to Bridger/Anticline 500 kV Transmission Project?

A. The mandatory standards, particularly NERC's TPL-001-4 standard, require the Company to have a forward-looking transmission plan of action to reliably serve current and anticipated customer demands under certain planning horizon conditions, including normal system operations (all system elements in service) and during system contingencies (where elements of the transmission system are out of service), both planned or otherwise.

As described earlier in my testimony, the Company performs annual reliability assessments to determine that its transmission system complies with minimum mandatory system performance standards, which require that during loss of any single transmission system element (N-1 single contingencies) that firm service is maintained, no system overloads exist, and there is no loss of customer demand.

The Aeolus to Bridger/Anticline 500 kV Transmission Project is sub-segment D.2 of Gateway West, which, as part of Energy Gateway, has been included in the Company's annual TPL-001-4 assessment as part of its short- and long-term plans to dependably meet NERC and WECC reliability requirements. The Aeolus to Bridger/Anticline 500 kV Transmission Project's new transmission segments are particularly effective in increasing system reliability under the various multiple contingency categories of the TPL-001-4 standard.

The NERC Standard TPL-001-4 has category P6 (N-1-1) that results in outage of multiple transmission elements. This category outage allows adjustment of the transmission system after the first outage following which the second outage is conducted. The Aeolus to Anticline 500 kV line will significantly help under these N-1-1 conditions. For example, the N-1-1 outage of Riverton to Wyopo 230 kV line followed with an outage of Spence to Mustang 230 kV line without the 500 kV line would require curtailment of the TOT 4A path by approximately 500 MW. But with the addition of the 500 kV line this curtailment would not be required. The study was performed with TOT 4A flows at 1,030 MW in the original case. The addition of the 500 kV line prevents thermal overload on the 230 kV transmission system west of Platte.

Q. Has the Aeolus to Bridger/Anticline 500 kV Transmission Project been included in WECC path rating studies?

A. Yes. The Aeolus to Bridger/Anticline 500 kV Transmission Project has undergone WECC's Three Phase Ratings Process, and has been approved by WECC for Phase 3-"Construction Phase" status as part of the overall Energy Gateway project. The

Aeolus West transmission path and three other Gateway West transmission paths (TOT 4A, Bridger/Anticline West and Path C) have completed the Three Phase Rating Process and were granted Phase 3 status on January 5, 2011.

Q. What is WECC's Three Phase Ratings Process?

A. The purpose of the Three Phase Rating Process is to provide a formal process for project sponsors to attain an accepted rating and demonstrate how their project will meet NERC Reliability Standards. The Three Phase Rating Process addresses planned new facility additions and upgrades, or the re-rating of existing transmission facilities. It requires coordination through a review group comprised of the project sponsors and representatives of other systems that may be affected by the project. An accepted rating affords the project sponsor some protection against erosion of established capacity of the rated transmission facility when further expansion of the western interconnected transmission system is proposed or new limitations are discovered.

Q. Why is WECC's Three Phase Ratings Process important to the Aeolus to Bridger/Anticline 500 kV Transmission Project?

A. This WECC approval is necessary because it allows the Company to interconnect the Aeolus to Bridger/Anticline 500 kV Transmission Project to the wider transmission system in the area and to reliably operate the new line at its approved ratings. The Aeolus to Bridger/Anticline 500 kV Transmission Project, especially when complemented with other Energy Gateway projects (specifically Aeolus to Clover, included in the 2019 Integrated Resource Plan (IRP) preferred portfolio, and Anticline to Populus and Oquirrh to Terminal, included in PacifiCorp's IRPs over the last several cycles), will greatly strengthen the Company's transmission capacity and flexibility. The Aeolus to Bridger/Anticline 500 kV Transmission Project is regarded as a necessary interconnection point to support the long-term transmission expansion planning established in the WECC Region plans and in the most recent Northern Tier Transmission Group (NTTG) sub-regional plan.[9]

While the Aeolus to Bridger/Anticline 500 kV Transmission Project provides the next necessary increment of transmission capacity in the area, it also supports and complements other future transmission investments that are currently proposed by the Company as included in the 2019 IRP preferred portfolio, provides recognition for continued permitting and supports the reliability of other utilities in the region as shown in the NTTG regional plans. The construction of this line, as an integral component of the larger Energy Gateway project, positions the Company to be strongly interconnected to other regional projects currently being planned and provides options for access to additional resources.

Q. What are the impacts to the system and the Company if the Aeolus to Bridger/Anticline 500 kV Transmission Project is not completed or delayed?

A. If the Aeolus to Bridger/Anticline 500 kV Transmission Project is not completed, the existing congestion will remain and the Company's ability to deliver resources to load will also remain constrained. As discussed above, the Company currently meets all

[9] PacifiCorp participates in FERC Order 1000 regional planning through membership in the NTTG. Under FERC Order 1000, regional planning groups were established to facilitate coordinated and transparent transmission system planning among the participating member entities to ensure regional transmission stability and efficiency. Currently, there are four sub-regions in the Western Interconnection of the United States, including NTTG, Columbia Grid, West Connect, and California ISO. These four sub-regions each develop independent regional plans and then coordinate on interregional planning across the Western Interconnection. Effective January 2020, NTTG and Columbia Grid will merge into the new Northern Grid regional planning group, of which PacifiCorp will be a participating member. Further information on NTTG is available at: http://nttg.biz/site/index.php?option=com_docman&task=cat_view&gid=308&Itemid=31.

applicable system reliability and performance criteria and therefore the Aeolus to Bridger/Anticline 500 kV Transmission Project is not strictly required to satisfy those standards. Rather, this project has long been identified as an important addition to the Company's transmission system, and the PTCs generated by the incremental wind resources provide a time-limited opportunity to build the Aeolus to Bridger/Anticline 500 kV Transmission Project now with only a moderate rate impact.

Q. How will the Aeolus to Bridger/Anticline 500 kV Transmission Project reduce energy and capacity losses?

A. Reduced energy and capacity losses on the transmission system have the potential to provide monetary savings over time. The addition of a new transmission line operated in parallel with existing lines reduces the electrical impedance of the transmission system, resulting in lower energy line losses (megawatt-hours) over the life of the project. Depending on the amount of power flow, line loss savings can be substantial.

Q. Did the Company consider alternatives to the Aeolus to Bridger/Anticline 500 kV Transmission Project?

A. Yes. While long-term alternatives to constructing a new transmission line are limited, the Company did consider other approaches, but none were cost-effective. As described more fully in the testimony of Mr. Link, the Aeolus to Bridger/Anticline 500 kV Transmission Project and Energy Vision 2020 Wind Projects were included in the Company's 2017 IRP, where they were analyzed in comparison to alternatives. The resource portfolio that included the Aeolus to Bridger/Anticline 500 kV

Transmission Project and Energy Vision 2020 Wind Projects was consistently the risk-adjusted, least-cost option.

The Company also considered the ability to obtain additional transmission capacity by upgrading the existing transmission system or implementing alternative transmission technologies. Indeed, since 2013 the Company has completed several important projects to enhance the transmission system in southeast Wyoming, including the dynamic line rating of the Miners (Standpipe) to Platte 230 kV line in 2013, Southern Wyoming Voltage Control Scheme, which coordinated wind generation reactive output to stabilize local area voltages, in 2015, and construction of the Standpipe substation and 60 megavolt-ampere-reactive (MVAr) synchronous condenser for voltage control in 2016. These projects allowed the Company to delay the Aeolus to Bridger/Anticline 500 kV Transmission Project until 2020, but were not a long-term substitute for the project.

Q. Is the Company confident that it can manage the construction schedule risk and deliver the Aeolus to Bridger/Anticline 500 kV Transmission Project by 2020?

A. Yes. To manage construction schedule risk, the Company is structuring and managing the project on a firm, date-certain, fixed-price, turnkey contract basis. Construction contractors and equipment suppliers will be held to key construction and delivery milestones and development of compressed schedule mitigation plans, if required. The Company also established construction contract completion dates and backstopped them with guarantees.

Q. Has the Company obtained all of the necessary permits and rights of way for the Aeolus to Bridger/Anticline 500 kV Transmission Project?

A. Yes.

Q. Has the Company made substantial progress on construction of the Aeolus to Bridger/Anticline 500 kV Transmission Project?

A. Yes. The Company has in place all contracts for construction of the Aeolus to Bridger/Anticline 500 kV Transmission Project, including contracts for construction of supporting 230 kV network upgrades. Construction work commenced in April 2019. As of early December 2019, the 500 kV transmission line had 98 percent of all foundations installed, 86 percent of structures erected and 41 percent of wire stringing completed. The Aeolus, Anticline, and Jim Bridger substations are under construction with grading complete and foundations, as well as underground construction, is ongoing. Steel erection and bus installation has commenced at Aelous, Anticline, and Jim Bridger substations. Major substation equipment is being manufactured and tested; first deliveries of circuit breakers have been received at all three substations, capacitor banks and reactive devices were delivered in December 2019, and the transformers will begin arriving in spring 2020. The Latham substation expansion is now complete and was placed in-service in December 2019. The voltage control device foundations and building enclosure are under construction with major equipment being manufactured and tested. Work at the Freezeout substation is complete, and the majority of the construction of the Shirley Basin substation to support the future 230 kV transmission has been completed with the remaining work scheduled to be completed in spring of 2020.

Q. What are the major milestones remaining before the December 2020 in-service date for the Aeolus to Bridger/Anticline 500 kV Transmission Project?

A. Major Milestones are identified below:

500 kV Transmission

- Mechanical Completion August 31, 2020
- Substantial Completion October 31, 2020

500 kV Substations

- Mechanical Completion Aeolus 230 kV yard; May 15, 2020
- Substantial Completion Aeolus 230 kV yard; June 15, 2020
- Mechanical Completion (all remaining work); August 31, 2020
- Substantial Completion (all remaining work); October 31, 2020

230 kV Network Upgrades

- Aeolus to Shirley Basin; Substantial Completion May 15, 2020
- Aeolus to Freezeout; Substantial Completion May 30, 2020
- Freezeout to Standpipe; Substantial Completion September 15, 2020
- Aeolus to Shirley Basin (rebuild); Substantial Completion September 30, 2020

Q. Are the transmission projects currently on budget and are they forecasted to be delivered on budget?

A. Yes.

Q. Please describe the estimated total cost of the Transmission Project.

A. The Aeolus to Bridger/Anticline transmission line and associated substations are estimated to cost $679.2 million, as summarized in Table 2 below.

TABLE 2	
Item	**Total Company Value**
Transmission Line	$234.6m
Substations	$214.1m
Engineering	$18.9m
ROW Acquisition	$16.0m
PM/Environmental/Support Works	$92.4m
In-directs	$86.7m
Contingency	$16.5m
TOTAL	**$679.2m**

The entire cost of the Aeolus to Bridger/Anticline project will be paid by the Company without contribution from any transmission customer projects.

The 230 kV transmission line and associated substations are estimated to cost $92.2 million, as summarized in Table 3 below.

TABLE 3	
Item	**Total Company Value**
Transmission Line	$53.15m
Substations	$12.67m
Engineering	$3.7m
ROW Acquisition	$1.06m
PM/Environmental/Support Works	$9.15m
In-directs	9.69m
Contingency	$2.78m
TOTAL	**$92.2m**

The Company expects that transmission customers will contribute to the cost of the 230 kV transmission interconnections. The 230 kV transmission facilities identified to integrate the Aeolus to Bridger/Anticline single-circuit 500 kV line with the existing Wyoming transmission system are considered network upgrades.

Q. If the Aeolus to Bridger/Anticline 500 kV Transmission Project is not fully in-service by December 31, 2020, can the Energy Vision 2020 Wind Projects still qualify for PTCs?

A. Yes. Assuming the Aeolus to Bridger/Anticline 500 kV Transmission Project is not completed by December 31, 2020, but otherwise has facilitated synchronization to the transmission grid and commissioning of individual wind turbines in accordance with Internal Revenue Service guidance, the Company would treat a completed and functional wind turbine as being placed in-service regardless of any transmission constraints affecting a wind project.

Q. How will the costs of the Aeolus to Bridger/Anticline 500 kV Transmission Project flow into the Company's transmission rates, and who will pay these rates?

A. Transmission assets, including new transmission capital like the Aeolus to Bridger/Anticline 500 kV Transmission Project, are included in the ATRR, weighted by months in-service. The ATRR is converted into a rate by dividing ATRR by firm transmission demand. All third-party revenues for transmission service (along with third-party revenues for ancillary services) are included as revenue credits in the calculation of rates in each of the Company's state retail jurisdictions.

VI. WALLULA TO MCNARY 230 KV NEW TRANSMISSION LINE PROJECT

Q. Please describe the investment for the Wallula to McNary 230 kV New Transmission Line Project.

A. The in-service Wallula to McNary 230 kV New Transmission Line Project consisted of two sequences of work, the combined costs of which are included in this general rate case filing. The first work sequence was placed in-service in December 2017 for $6.4 million and included expansion at PacifiCorp's Wallula substation, as well as, relay and communications work at the Nine Mile substation. The second sequence of work was the construction of the new 230 kV transmission line that went into service in January 2019 for $36.2 million. A one-line diagram of the Wallula to McNary 230 kV New Transmission Line project is included in Exhibit PAC/1002.

Q. Please explain why this investment in the Wallula to McNary 230 kV New Transmission Line Project was needed and beneficial.

A. The Wallula to McNary 230 kV New Transmission Line Project was needed to enable PacifiCorp to comply with PacifiCorp's OATT, its transmission service agreements, and FERC's requirements to provide the requested transmission service. Before this line went into service, there were only two MW of available transfer capacity on the existing line between Wallula and McNary, which was insufficient to satisfy the requests for service from providers of generation capacity from renewable resources. The completion of the project now enables PacifiCorp to fulfill such requests in compliance with its OATT requirements, and will also increase the Company's access to generation capacity from renewable resources.

In addition, the project enhances transmission reliability by providing a second connection between the Bonneville Power Administration's (BPA's) McNary substation and PacifiCorp's Wallula substation. With only a single line between Wallula and McNary, line outages, either planned or unplanned, cause disruption of service to customers. This disruption can result in loss of service under existing contracts or reduced reliability for customers served from the Wallula substation.

This new second line will provide service reliability in a single line outage condition, and, because it was constructed with lightning protection, the new line reduces lightning-caused voltage sag events in the area.

Q. Did PacifiCorp consider alternatives to investing in the Wallula to McNary 230 kV New Transmission Line Project?

A. Yes. In lieu of the selected project, PacifiCorp considered re-building the existing Wallula to McNary 230 kV transmission line to a double circuit line, but this project had an estimated cost of $73.6 million. As a second alternative, PacifiCorp considered re-conductoring the existing Wallula to McNary 230 kV transmission line with high temperature conductor. This alternative would have required the addition of phase shifting transformers to produce increased flow on the line and a new substation to place the equipment at an estimated cost of $53.6 million. Both alternatives were rejected due to cost savings associated with investing in the Wallula to McNary 230 kV New Transmission Line Project.

VII. SNOW GOOSE 500/230 KV NEW SUBSTATION PROJECT

Q. Please describe the investment for the Snow Goose 500/230 kV New Substation Project.

A. This in-service project constructed a new 500/230 kV substation located near Klamath Falls, Oregon, as shown on the map attached in Exhibit PAC/1003. The new Snow Goose substation has a 500/230 kV, 650 MVA transformer bank and associated switchgear. In addition, PacifiCorp constructed 0.5 miles of 230 kV transmission line and 1.2 miles of 500 kV transmission line to integrate the substation into the area's 230 kV and 500 kV systems. The 230 kV yard was placed in-service in May 2017, and the 500 kV yard was placed in-service in November 2017, for a total of $42.8 million. A one-line diagram of the Snow Goose 500/230 kV New Substation Project is also included in Exhibit PAC/1003.

Q. Please explain the benefits of this investment in the Snow Goose 500/230 kV New Substation and why it is needed.

A. The need for the Snow Goose 500/230 kV New Substation Project was based on achieving continued compliance with reliability standards mandated by NERC under the TPL Standards. In 2012, PacifiCorp performed TPL Standards screening studies that identified system performance deficiencies following the single contingency loss of PacifiCorp's existing 500/230 kV, 650 MVA transformer bank at Malin substation. Specifically, PacifiCorp determined that during the 2017 projected summer peak load conditions, the loss of the transformer bank would result in the system failing to meet the low voltage limits on the PacifiCorp-owned 230 kV, 115 kV and 69 kV systems and an increase in the load on the Copco to Lone Pine 230 kV line. By 2027, the Copco to Lone Pine 230 kV line would exceed its rated thermal continuous and emergency capacity during this outage. This outage would also cause a reduction of the power flow on the Alturas to Reno WECC Path 76. As a result, firm scheduled transfers on this line could not continue to be supported without a second 230 kV source.

Construction of the Snow Goose substation provided a second 500 kV to 230 kV transmission tie in the area that ensured that PacifiCorp is able to maintain adequate system voltage and power delivery during a single contingency outage condition, thus maintaining service for customers in southern Oregon and northern California.

Q. Did PacifiCorp consider alternatives to investing in the Snow Goose 500/230 kV New Substation Project?

A. Yes. In lieu of the Snow Goose 500/230 kV New Substation Project, PacifiCorp considered resolving the deficiencies under the TPL Standards by installing a second transformer at Malin substation and building a second line from Malin to Klamath Falls. This alternative was rejected as Malin substation could not be readily expanded to accommodate a new 500/230 kV transformer position due to physical site constraints. This alternative was estimated to be $85.0 million.

A second alternative would have involved installing a 500/230 kV, 650 MVA transformer at the BPA-owned Captain Jack substation and building 27 miles of 230 kV line from Captain Jack to Klamath Falls. Adding another transformer at the Captain Jack substation would require increasing the size of the substation property and reaching an agreement with BPA. This alternative was estimated to be $90.0 million and was rejected because of insufficient space at the BPA-owned Captain Jack substation, inadequacy of the site in serving as a new source of 69 kV to the Klamath Falls metropolitan area, and additional reinforcement requirements of the 230 kV path between Captain Jack and Klamath Falls substations.

The last alternative considered would have involved installing a 500/230 kV, 650 MVA transformer at the Klamath Co-Gen substation and building a new 230 kV line to tap the Klamath Falls to Boyle 230 kV line. As with the first alternative, this option was rejected due to space and cost limitations. Estimated costs for this alternative were $85.0 million.

VIII. VANTAGE TO POMONA HEIGHTS 230 KV NEW TRANSMISSION LINE PROJECT

Q. Please describe the investment for the Vantage to Pomona Heights 230 kV New Transmission Line Project.

A. The Vantage to Pomona Heights 230 kV new transmission line consists of a new 41-mile 230 kV transmission line that extends from BPA's Vantage substation near Vantage, Washington, and ends at PacifiCorp's Pomona Heights substation in Yakima, Washington, as shown on the map attached in Exhibit PAC/1004. The project consists of two sequences of work. The first work sequence to expand the Pomona Heights substation 230 kV ring bus to provide adequate breaker separation between lines and transformers for breaker failure and bus fault events was placed in-service in November 2015 for $9.4 million. The second sequence of work is projected to be placed in-service in May 2020 for an estimated $57.3 million and includes the installation of a new 230 kV transmission line connected at BPA's Vantage substation and ending at the Pomona Heights substation. The Company has now received full federal permissions to construct this transmission line. The final segment permission was received from the Bureau of Land Management on September 27, 2019. This portion of the project will include the installation of breakers, protection and control equipment, and communications equipment at each substation as required to monitor and safely operate the new line. The infrastructure additions at Vantage substation will be designed, purchased, installed, and maintained by BPA. A one-line diagram of the Vantage to Pomona 230 kV new transmission line is also included in Exhibit PAC/1004.

Q. Please explain why this investment in the Vantage to Pomona Heights 230 kV New Transmission Line Project is needed and beneficial.

A. The need for the Vantage to Pomona Heights 230 kV project was identified through internal planning studies and a coordinated Northwest Transmission Assessment Committee study in 2007. NERC screening studies conducted in 2009 and subsequent NERC screening studies additionally identified TPL Standards performance deficiencies following breaker failure and bus fault events on the Pomona Heights 230 kV bus and various N-1-1[10] outages associated with the Wanapum to Pomona Heights 230 kV line. Breaker failure and bus fault and N-1-1 events on other portions of the Yakima 230 kV and 115 kV systems resulted in additional TPL Standards performance deficiencies. In total, there are eight contingency combinations that were identified that could give rise to the need to shed Yakima area load. The Yakima area is currently served primarily by two 230 kV transmission sources. The loss of both primary 230 kV sources or loss of one primary 230 kV source and another major element in the underlying system leaves the remaining system unable to provide adequate electric service to all customers in the area.

The addition of a new 230 kV line between Vantage and Pomona Heights substations and providing a third 230 kV source to the area mitigates the identified deficiencies. Specifically, the project eliminates the need to shed Yakima area load

[10] See footnote 2 for a description of N-1-1 events.

for those eight contingency combinations and eliminates overloads in the PacifiCorp and BPA transmission systems with loss of the existing line.

By enabling PacifiCorp to comply with the TPL Standards and increasing the reliability of PacifiCorp's transmission system by eliminating the need to shed Yakima area load under certain outage conditions, this project provides benefits to customers.

Q. Did PacifiCorp consider alternatives to investing in the Vantage to Pomona 230 kV New Substation Project?

A. Yes. In lieu of the selected project, the new 230 kV line from Vantage to Pomona Heights, PacifiCorp considered constructing a new 500/230 kV transformer and bus position at Wautoma substation and a new 230 kV transmission line from Wautoma substation to Pomona Heights substation resulting in an estimated cost of $89.6 million. This alternative was rejected because the costs were higher than the selected project. Another alternative would have involved constructing a second 230 kV transmission line from Midway substation to Union Gap substation. This alternative was rejected, however, because it would have corrected identified deficiencies for only approximately 10 years before additional transmission reinforcement would be required.

IX. GOSHEN TO SUGARMILL TO RIGBY 161 KV TRANSMISSION LINE PROJECT

Q. Please describe the investment for the Goshen to Sugarmill to Rigby 161 kV Transmission Line Project.

A. The Goshen to Sugarmill to Rigby 161 kV Transmission Line Project constructs approximately 44 miles of new transmission lines from the Goshen to Sugarmill and Sugarmill to Rigby substations located in the southeast Idaho area. Substation expansion will be required at Goshen, Sugarmill, and Rigby substations to accommodate the new 161 kV positions and associated structures and equipment, as shown on the map attached in Exhibit PAC/1005. The project consists of two sequences of work. The first work sequence, planned to be placed in-service in November 2020 for $21.5 million, is to construct approximately 24 miles of the new Goshen to Sugarmill #2 161 kV transmission line and perform the required substation construction at Goshen and Sugarmill substations to terminate the new transmission line at both ends. The new 161 kV line consists of approximately 22.2 miles of 69 kV line rebuilt to 161 kV and 1.6 miles of new double circuit construction into Sugarmill substation. Substation work includes yard expansion for adding the new 161 kV line positions and installation of transmission dead-end structures, substation bus and associated disconnect switches, and breakers. The substation work also includes the installation of protection and control equipment, and communications equipment at each substation as required to monitor and safely operate the new line. The second work sequence is planned to be placed in-service in November 2022, which falls outside of the scope of this case. The second sequence will consist of constructing approximately 20 miles of the new Sugarmill to Rigby #2 161 kV line and performing the required substation construction at Goshen and Sugarmill substations to terminate the new transmission line at both ends of the line.

Q. Please explain why this investment in the Goshen to Sugarmill to Rigby 161 kV Transmission Line Project is needed and beneficial.

A. The need for the Goshen to Sugarmill to Rigby 161 kV line was identified in the 2016 Goshen Area Planning Study to address projected overloads on the Goshen to Sugarmill 161 kV line and Goshen to Rigby 161 kV line, in addition to low voltage at Rigby and Sugarmill substations that manifest under heavy loading conditions. Projected peak summer load conditions in 2021 in the Rigby-Sugarmill area indicate that under normal operating conditions (N-0) the Goshen to Sugarmill 161 kV line is expected to load to 100 percent of its continuous rating of 201 MVA and the Rigby and Sugarmill substations 161 kV bus voltage is expected to reach its minimum limit of 0.95 per unit. Additionally, the projected load growth exacerbates several existing N-1 conditions in the area. Based on 2021 load, loss of the Goshen to Sugarmill 161 kV line causes the Goshen to Rigby 161 kV line to overload to 179 percent of its four-hour emergency rating and can result in excessively low voltage down to 0.68 per unit in the Rigby-Sugarmill area. The loss of the Goshen to Rigby 161 kV line can cause the Goshen to Sugarmill 161 kV line to overload to 111 percent of its four-hour emergency rating of 255 MVA, overload to 102 percent of its 30-minute emergency rating of 279 MVA, and can cause low voltage down to 0.88 per unit at Rigby substation. The Goshen to Sugarmill 161 kV line and Goshen to Rigby 161 kV line are operated radially during summer heavy loading periods to mitigate the risk of violating NERC Standard TPL-001-4 category P0 (N-0), P1 (N-1) and P6 (N-1-1) performance requirements due to transmission capacity deficiencies in the area. Operating radially puts approximately 150 MW load at risk for N-1 loss of either the Goshen to Sugarmill 161 kV line or the Goshen to Rigby 161 kV line and 300 MW at risk for N-1-1 loss of any two transmission lines.

The new Goshen to Sugarmill to Rigby 161 kV line will increase load serving capacity in the Rigby to Sugarmill area by 250 MVA that will allow the transmission lines between Goshen, Sugarmill, and Rigby substations to operate in a normal loop configuration and N-1 thermal overload and low voltage issues on the remaining transmission line and substation. Benefits also include elimination of the N-0 overload risk, improved load service reliability under N-1 conditions, and resolution of most N-1-1 issues present in the area.

Q. Did PacifiCorp consider alternatives to investing in the Goshen to Sugarmill to Rigby 161 kV Transmission Line?

A. Yes. The first alternative in lieu of the Goshen to Sugarmill to Rigby 161 kV line that PacifiCorp considered was a project to construct a new approximately 35-mile long Goshen to Rigby 345 kV line with 1272 aluminum conductor steel-reinforced (ACSR) cable and add a new 450 MVA capacity or larger 345/161 kV transformer at the Rigby substation. Work involved expanding both the Goshen and Rigby substation yards to accommodate the new facilities consisting of at least two 345 kV breakers at Goshen, one 345 kV breaker at Rigby and at least two 161 kV breakers at the Rigby 161 kV substation. This alternative was rejected since the estimated cost of the project was about $17.0 million higher than the chosen project to construct the new Goshen to Sugarmill to Rigby 161 kV transmission line. The alternative was estimated to be $57.7 million.

A second alternative considered was to construct an approximately 61-mile-long Antelope to Rigby 161 kV transmission line with 1272 ACSR cable or larger. Work involved expanding both the Antelope and Rigby substation yards to accommodate the new facilities consisting of at least two 161 kV breakers at Antelope and at least two 161 kV breakers at Rigby. A new 161 kV line from Antelope would provide a new source into the Rigby to Sugarmill area apart from Goshen substation; however, planning studies indicated that by adding the Antelope to Rigby 161 kV line, the N-1 loss of the Goshen to Sugarmill 161 kV line would still cause thermal overload and low voltage issues in the area and that load shedding and radialization of the Rigby to Sugarmill area would still be required. This alternative was rejected since the estimated cost of the project was about $8.0 million higher than the new Goshen to Sugarmill to Rigby 161 kV transmission line and that a new Antelope to Rigby 161 kV transmission line does not resolve the loading and voltage issues in the Rigby to Sugarmill area. The alternative was estimated to be $48.0 million.

A third alternative considered was to construct approximately 22.8 miles of a 161 kV transmission line from the Meadow Creek wind farm substation to Sugarmill and Rigby substations to create a looped transmission source back to Goshen substation. Work involved constructing approximately 5.9 miles of new single circuit 161 kV transmission line from Meadow Creek to a new tap location, using the existing right of way to construct 4.5 miles of double-circuit line from the new tap location to Sugarmill substation, and construct 12.4 miles of new single-circuit

161 kV line from the new tap location to Rigby substation. Work also included converting Meadow Creek's 161 kV substation yard into a new three breaker ring bus, installation of at least two 161 kV breakers at Sugarmill and Rigby substations, rebuilding the Goshen to Wolverine Creek to Jolly Hills to Meadow Creek 161 kV line with 1557 ACSR cable (approximately 32.4 miles), rebuilding the remaining three miles of 795 all-aluminum conductor (AAC) cable on the Goshen to Sugarmill 161 kV line, and adding a 161 kV bus tie breaker at Rigby to facilitate sectionalizing post N-1. Currently, the Goshen wind farms are radial from the Goshen 161 kV substation. Once looped through the Rigby and Sugarmill substations, a detailed voltage control study would be required to coordinate the wind farms and shunt devices in the area. Since the existing radial wind farm line is owned and operated by third parties, an agreement to use or buy the facilities would need to be negotiated. This alternative was rejected since the estimated cost of the project was about $8.2 million higher than the new Goshen to Sugarmill to Rigby 161 kV transmission line and required significant coordination with third parties to deliver the project. The alternative was estimated to be $48.5 million.

The last alternative considered was to loop the existing Goshen to Jefferson 161 kV transmission line in and out of the Bonneville substation. Work involved converting the Bonneville substation into a 161 kV breaker and one-half configuration, constructing an approximately 27-mile-long 161 kV line from Bonneville to Rigby substation with at least 1557 ACSR cable. Work also involved expanding both the Rigby substation yards to accommodate a new 161 kV line position consisting of at least two 161 kV breakers at the Rigby substation. Adding this new Bonneville to Rigby 161 kV line does not improve N-1 and N-1-1 issues in the area and therefore is not considered as a viable alternative. The estimate for this project was $33.2 million. Additional projects would be required to address the N-1 and N-1-1 issues. These projects include reconductoring 32 miles of Goshen to Rigby 161 kV line, reconductoring 16 miles of Sugarmill to Rigby 161 kV line, and reconductoring 3.5 miles of 795 AAC cable on existing Goshen to Sugarmill 161 kV line. Additionally, a new Goshen to Sugarmill 161 kV line would be required to mitigate the low voltage and voltage swings caused by the loss of the existing Goshen to Sugarmill 161 kV line. The estimate to reconductor these lines was $6.6 million and the estimate to construct a new Goshen to Sugarmill 161 kV line was $13.3 million. This alternative was rejected since the estimate for the new Bonneville to Rigby 161 kV line and supporting projects was about $12.7 million higher than the recommended new Goshen to Sugarmill to Rigby 161 kV transmission line project. The alternative was estimated to be $53.1 million.

X. SIGURD TO RED BUTTE 345 KV TRANSMISSION LINE PROJECT

Q. Please describe the investment for the Sigurd to Red Butte 345 kV Transmission Line Project.

A. This in-service project constructed a new 170-mile single circuit 345 kV line from Sigurd substation in Sevier County, Utah to Red Butte substation in Washington County, Utah, as shown in the map attached in Exhibit PAC/1006. This project was placed in-service in three sequences. The first sequence, placed in-service in May 2013, was the Three Peaks series capacitor upgrade. The second sequence included all segments of the new 345 kV transmission line, as well as the required upgrades and modifications at Red Butte and Sigurd substations. Sequence three was the completion of the final cultural report required as part of the National Environmental Policy Act permitting process.

Q. Please explain the benefits of this investment in the Sigurd to Red Butte 345 kV line and why it is needed.

A. The Sigurd to Red Butte 345 kV line provides a reliable and adequate supply of electricity to meet existing and future electrical loads. Without the increased transmission capacity provided by the Sigurd to Red Butte 345 kV line, the Company would have been faced with an increased and unacceptable risk of not being able to meet its load service obligations during peak periods. The Sigurd to Red Butte 345 kV transmission line enhances the Company's ability to provide safe, reliable, and efficient service to all customers. Further, in order to provide low-cost energy, the Company must have the ability to acquire power from numerous generation sources in order to negotiate the most competitive pricing.

The addition of the Sigurd to Red Butte 345 kV line is an important piece in strengthening the Western Interconnection transmission infrastructure. The Sigurd to Red Butte 345 kV line has resulted in a stronger interconnection with other parts of the Western Interconnection, providing better transmission system access to the other sources of generation. The Sigurd to Red Butte 345 kV line, especially when complemented with other projects, such as the Populus to Terminal transmission project and the Mona to Oquirrh transmission project, greatly strengthens the Company's transmission capacity and flexibility. This is necessary, based upon the near-term and long-term load growth projections of the Company and its transmission customers, as well as the contingencies and restrictions occurring on the system during outage conditions.

Q. Has the investment in the Sigurd to Red Butte 345 kV line enhanced PacifiCorp's access to wholesale markets?

A. Yes. By adding transmission capacity, the Company has increased its ability and options to obtain power from additional generation sources at competitive pricing. In December 2015, Nevada Energy joined the EIM and established an Energy Transfer System Resource (ETSR) at Red Butte. The Red Butte ETSR provides PacifiCorp the ability to facilitate intra-hour transfers between NV Energy and the rest of the EIM footprint. Were it not for the investment in the transmission segment, PacifiCorp's EIM transfer capability would likely be 200 MW lower at this ETSR, providing less benefits to PacifiCorp's customers.

Q. Please explain the benefits of the investment in the Three Peaks series capacitor upgrade and why it is needed.

A. To support the additional load flows brought about by the completion of the new Sigurd to Red Butte 345 kV line, the Three Peaks series capacitor needed to be modified to increase the current (ampere) rating. The Three Peaks series capacitor upgrade had to be placed in-service before placing the new transmission line between Sigurd and Red Butte substations in-service. With the completion of the Three Peaks series capacitor project ahead of the completion of the Sigurd to Red Butte 345 kV line, the southern Utah transfer capability was increased for the 2013 and 2014 summer operating periods, and additionally to provide the same functions for the 2015 summer operating period if the transmission line project was delayed.

Q. Please explain the reason for the final cultural report completed in June 2017.

A. The report was a summary and interpretation of all archeological investigation and treatment that was required during construction. During the federal permitting process for the project, several archeological sites were identified where treatment was required throughout the project. The treatments included such things as photo documentation, barricading, monitoring, and excavation/investigation. The final report summarized what was found on the project, how it was treated, the results of any analyses which were required, and an interpretation of the historical significance of the artifacts. All archeological field work was completed in 2015; however, the report was not complete until 2017 due to the extensive laboratory analysis, research and writing that was necessary in the report preparation.

Q. Did PacifiCorp consider alternatives to investing in Sigurd to Red Butte 345 kV Transmission Line Project?

A. The Company took significant steps to identify and implement alternatives that delayed the need for the Sigurd to Red Butte 345 kV Transmission Line Project. These included: 1) completion of interim projects in 2009 which added major equipment to the existing Three Peaks substation, thus improving the 345 kV system operation and increasing reliability for serving the general area; 2) addition of major equipment and devices in 2011 to the existing Red Butte substation, which increased system capacity, improved voltage support, and maintained the reliability of the system in the general area; and, 3) the addition of a 345/230 kV 375 MVA transformer, also in 2011, to the Harry Allen substation. These projects, along with special operating procedures, allowed the Company to delay the Sigurd to Red Butte line until the summer of 2015.

PacifiCorp also considered advancing construction of a 345 kV transmission line from Sigurd to St. George, Utah. The 2011 Southwest Utah Joint Study Report, conducted in association with Utah Associated Municipal Power Systems, Deseret Power, and PacifiCorp determined that a future transmission line beyond the proposed Sigurd to Red Butte 345 kV Transmission Line Project will be needed between Sigurd and St. George, Utah, when load and reliability requirements reach a critical point, at the time estimated to be beyond 2025.[11] The planned Sigurd to St. George, Utah 345 kV line will be 185 miles in length, compared to 170 miles for the Sigurd to Red Butte 345 kV line, and would have been more costly and provided fewer system benefits than the enhanced interconnection with a neighboring balancing authority area. Additionally, the future line will connect to four substations instead of the two which the Sigurd to Red Butte 345 kV line connects to.

XI. NORTHEAST PORTLAND TRANSMISSION UPGRADE PROJECT

Q. Please describe the investment for the Northeast (NE) Portland Transmission Upgrade Project.

A. The NE Portland Transmission Upgrade was a systematic solution resolving several operational and contingency related network issues in the Portland transmission and substation system, as shown on the map attached in Exhibit PAC/1007. Due to the complexity and duration of the scope, this project was placed in-service in six sequences for a total of $20.6 million. The first sequence of work was the conversion

[11] Updated studies now indicate load and reliability requirements in the area do not require additional action until 2028.

of the Parkrose substation from 57 kV to 115 kV, utilizing existing transformers, replacing open air bus-work with switchgear and replacing the 57 kV structure and equipment to implement substation conversion to 115 kV. This phase was placed in-service in December 2016 for $8.4 million. The second sequence of work, placed in-service in December 2016 for $800,000, was to re-insulate approximately 7 miles of 57 kV and 69 kV transmission line by replacing the existing insulators with 115 kV insulators, along with any necessary structure replacements to accommodate the new insulator configuration, as required for the voltage conversion. The third sequence was to convert the Columbia substation from 57 kV to 69 kV, re-deploying two existing transformers. This sequence was placed in-service in December 2018 for $3.9 million. The fourth sequence was to convert the Vernon substation from 69 kV to 115 kV, retaining the existing transformer and reconfiguring the upgraded transmission lines. This sequence was also placed in-service in December 2018 for $1.0 million. The fifth and sixth sequence replaced the two existing transformers at Albina substation with two standard transformers having voltage regulation. The new Albina transformer 1, along with associated substation upgrades and reconfiguration was placed in-service in December 2018 for $4.9 million, and the second transformer was placed in-service in May 2019 for $1.6 million.

Q. Please explain the benefits of the NE Portland Transmission Upgrade Project and why it was needed.

A. There were four primary issues addressed by this project. The first was the system capacity limitations with the Albina to Troutdale 69 kV Sundial transmission line. Before completion of this project, full outage restoration was not possible for a loss of either the Troutdale to Alderwood or the Albina to Vernon sections of the Sundial transmission line. For a loss of the Troutdale to Alderwood section, this would have resulted in a 0.8 mile section of 350 copper conductor loaded up to 117 percent and a 2 mile section of 795 ACSR loaded up to 108 percent of thermal capability. The load shedding exposure for summer 2015 was 14 MVA over 62 hours over 7 days. For a loss of the of Albina to Vernon section the resulting loading would have been up to 111 percent for 7.3 miles of the 795 ACSR conductor. The load shedding exposure for summer 2015 for the loss of this line segment was 10 MVA over 47 hours over six days based on the load duration curve for the line. Before this project, a single contingency on the Sundial line resulted in loss of service to three distribution substations: Vernon, Killingsworth, and Alderwood. Killingsworth and Alderwood are the primary sources to medical and government services. In May 2015, an outage occurred that, due to this system's capacity limitations, impacted 6,644 customers with an outage lasting up to 44 minutes, resulting in 284,416 customer minutes lost and an increase to SAIDI of 0.36 for PacifiCorp.

The second issue the project addressed was at Albina substation. There were two components to address at Albina. Transformer T-901 at Albina was built in 1949 and was showing signs of internal insulation breakdown based on oil tests. The oil was processed to improve quality and extend the life of the transformer but replacement was needed. The transformer secondary winding provided a source for the Albina to Troutdale 69 kV Sundial Line and the tertiary winding was used as the 11.7 kV source for the distribution network serving the north portion of downtown Portland. Utilizing the tertiary winding of the transformer resulted in higher fault current values on the distribution system. Due to the high fault currents, a standard voltage regulator to maintain proper voltage on the distribution system could not be used. Instead, the voltage on the 11.7 kV bus was regulated manually by dispatch using a system of Supervisory Control & Data Acquisition alarm levels in the energy management system, and was accomplished by switching four 6 MVAr capacitor banks on and off the system. Manual voltage regulation increased the opportunity for system voltages to be outside the range of mandated acceptable limits.

The third issue related to two existing NERC TPL deficiencies for NERC Standard TPL-001-4 that identify system overload conditions that existed, but which the conversion of Parkrose substation and the conversion of the identified line segments to 115 kV solved. The NE Portland Transmission Upgrade retired the 69 kV source and yard at Albina, which positioned the system for the planned future solution involving conversion of an existing 57 kV line to 115 kV to provide a third 115 kV path between the North Portland transmission sources and the PacifiCorp Portland area system.

The fourth issue was system operability on the existing 57 kV transmission system. Parkrose substation was designed with the intent to be able to transfer load to other substations for service; as such, it lacked mobile access and a bus tie breaker. Parkrose substation was the last 57 kV to 12.5 kV distribution substation in PacifiCorp's system. Load transfer options during peak conditions were no longer an option, and no spare or mobile existed to address outage recovery. The remaining 57 kV transmission lines are feed from the Knott 115 kV to 57 kV substation and have inter-ties with Portland General Electric Company's 57 kV system, which will be converted as both companies have plans for eventual elimination of the 57 kV transmission voltage within the Portland network.

Q. Did PacifiCorp consider alternatives to investing in the NE Portland Transmission Upgrade Project?

A. Yes. Options to remedy the capacity issue of the existing Sundial line were explored with the distributed energy resource (DER) development group. The conclusion was there was not a DER solution to address the Sundial capacity issues based on the provided load curve and duration needed. Application of energy storage technology to defer construction was also evaluated as an alternative to the infrastructure improvements on the Sundial line. To provide an equivalent solution for the immediate deficiency, with a small margin for load growth, the energy storage would have needed to be capable of providing 15 MVA from roughly 6:00 a.m. until 10:00 p.m. based on a winter load profile with a charging window of about 5 hours and a peak demand that avoids equipment overload (about 25 MVA). It should be noted that the required energy output greatly exceeded the available energy input, and significant infrastructure upgrade or addition would have needed to be constructed to facilitate the installation of the alternative. The NE Portland Transmission Upgrade Project fully mitigated the issues identified beyond the planning horizon.

An additional alternative was explored that would result in greater long-term system benefit. The solution would require construction of a new transmission line at an estimated cost of $85 million. This alternative was the most expensive, and the ability to permit and construct through the NE Portland urban area was anticipated to be extremely challenging. As a result, the solution was not deemed a viable alternative.

XII. SOUTHWEST WYOMING SILVER CREEK 138 KV TRANSMISSION LINE PROJECT

Q. Please describe the investment for the Southwest Wyoming Silver Creek 138 kV line.

A. This project was placed in-service in August 2017 for $41.9 million and included the siting, permitting, and rebuilding of approximately 70 miles of 46 kV transmission line at 138 kV, the construction of a new 138/46 kV substation (near Henefer, Utah), the removal of the Henefer substation, and the conversion of the Coalville substation to 138 kV. A project map and subsequent scope change diagram are included in Exhibit PAC/1008.

Q. Please explain the benefits of this investment in the Southwest Wyoming Silver Creek 138 kV line and why it is needed.

A. In the winter of 2009 to 2010, Park City, Utah's load peaked at 181 MVA. This is 113 percent of the winter thermal limit of either of the 138 kV lines serving the area. The area load exceeding 160 MVA could result in load loss under multiple outage scenarios due to the loss of either 138 kV source to the area or the Midway 138/46 kV transformer. These scenarios resulted in low voltages at best and cascading outages at worst. The following conditions for N-1 scenarios were expected and mitigated by the project:

- An N-1 fault on the Hale to Midway 138 kV line or a fault on the Midway 138/46 kV transformer could have caused: an outage to the Wallsburg substation (2.5 MVA – 650 customers), the Park City to Judge 46 kV line loads to 108 percent (58 MVA) of the winter rating (relay settings set at 76

MVA), the Park City to Silver Creek 46 kV line loads to 123 percent (66 MVA) of the winter rating (relay settings set at 67 MVA), and all voltages remained above 95 percent.

- An N-1 fault on the Cottonwood-Silver Creek 138 kV line could have caused: an outage to the Snyderville substation (35 megavolt-amps – 4,650 customers), the Midway 138/46 kV transformer loads to 104 percent (93 MVA) of the winter rating, the Brighton 46 kV voltage drop to 90 percent, the Henefer 46 kV voltage drop to 90 percent, and the Silver Creek 138 kV voltage drop to 88 percent (results from back-feeding the Silver Creek 138/46 kV transformer, which is normally set to boost voltage, is now bucking voltage). Silver Creek's 12.5 kV voltage drops to 99 percent with the regulation at full boost, and the Jordanelle 138 kV voltage drops to 88 percent and the 12.5 kV voltage levels drop to 99 percent with the regulation at full boost.

- An N-1 fault on the Park City-Judge 46 kV lines could have caused the Brighton 46 kV voltage levels to drop to 92 percent, but the 12.5 kV and 25 kV voltages remain at 1.02 percent due to the regulators.

Q. Did PacifiCorp consider alternatives to investing in the Southwest Wyoming Silver Creek 138kV line?

A. Yes. The first alternative considered was to rebuild the existing 138 kV and 46 kV lines in the Park City area with 1272 ACSR conductor and convert both Judge and Wasatch substations to 138 kV for a total estimated cost of $79.3 million. This alternative was rejected due to the higher cost and difficulty in permitting in the Park City area. The second alternative was to build a new 138 kV line from the Butlerville substation in Salt Lake City to the Brighton substation, rebuild the existing Brighton-Judge 46 kV line to 138 kV, rebuild the Judge to Silver Creek 46 kV line with single and double circuit 138 kV construction, and convert Brighton and Judge substations to 138 kV. All lines would be built using 1272 ACSR conductor. The total estimated cost for this alternative was $78.2 million. This alternative was rejected due to the higher cost and line routing through wilderness-designated areas. The final alternative considered was to build a 265-mile 230 kV line from the Hayden/Craig generating plant in Colorado through the Vernal area to Park City. This project provided additional benefits because of the ability to deliver generation located in Colorado into the Salt Lake area. There was no firm commitment with this project, but it could have been a third source into the Park City/Salt Lake area. The estimated cost for this alternative was estimated to be greater than $100 million and was rejected due to higher cost and construction timing.

XIII. THREEMILE CANYON FARM PROJECT

Q. Please describe the investment for the Threemile Canyon Farm Project.

A. This in-service project added a fourth 230/34.5 kV, 25 MVA transformer and a third 34.5 kV feeder position at the existing Dalreed substation and upgrades to the local 34.5 kV and 4.16 kV distribution system located near Boardman, Oregon, as shown on the map attached in Exhibit PAC/1009. Before this project, Dalreed substation consisted of three 230/34.5 kV transformers, sized 25 MVA, 20 MVA and 25 MVA, respectively, designed for redundancy such that the area irrigation load could remain served for an outage to any single transformer. The addition of the fourth transformer increased the substation designed capacity from 45 MVA to 70 MVA. The project was placed in-service in April 2015, for a total of $6.2 million. A one-line diagram of the Threemile Canyon Farm Project is also included in Exhibit PAC/1009.

Q. Please explain the benefits of this investment in the Threemile Canyon Farm Project and why it is needed.

A. This project was initiated as a 2,500 horsepower (HP), later increased by the customer to 3,150 HP (approximately 2.68 MW), load addition request from Threemile Canyon

Farm, LLC and evaluated under the Electric Services Study Agreement process. The load interconnection system impact study report identified the following impacts:

- The requested 2.68 MW (3.15 MVA) load addition increased the total Dalreed substation load to 51.76 MVA.
- An outage of either of the two 230/34.5 kV, 25 MVA transformers would result in forced load curtailment down to the remaining 45 MVA capacity.
- An outage of the 230/34.5 kV, 20 MVA transformer would result in forced load curtailment down to the remaining 50 MVA capacity.
- The requested load additions would increase loading on the Simtag feeder to 38.9 MVA, 86 percent of the conductor thermal rating. The PacifiCorp feeder loading guideline at 34.5 kV is 23.9 MVA and replacement of the conductor is recommended when loadings exceed 85 percent of thermal ratings.

The study identified the addition of a fourth 230/34.5 kV, 25 MVA transformer and third 34.5 kV feeder at Dalreed substation, along with the associated distribution upgrades as the recommended solution to ensure the system would have full N-1 capability at the 230/34.5 kV transformer level and each of the three 34.5 kV feeders would remain within guideline ratings.

Q. Did PacifiCorp consider alternatives to investing in the Threemile Canyon Farm Project?

A. Yes. The system impact study performed under an Electric Services Study Agreement evaluated two alternatives. The first alternative considered constructing a new 230/34.5 kV substation on new property near Dalreed substation. This alternative would have met the load customer's request while providing the potential benefits of allowing construction to occur without concern for outages and construction related loading limitations on the Dalreed area 34.5 kV system. The new substation alternative would also allow for easier expansion in the future if customer load continues to grow. However, construction of new facilities on new property was estimated to cost significantly more, at $8.5 million. Additionally, a new 230 kV interconnection would be required with BPA's Jones Canyon to McNary 230 kV line, potentially carrying higher costs and extending the construction timeline by three to five years. Due to the higher cost and longer timeline, this alternative was rejected.

The second alternative considered purchasing the fourth 230/34.5 kV, 25 MVA transformer but keeping it as an on-site spare instead of constructing the remaining substation improvements. Under this alternative, any 230/34.5 kV transformer failure would have resulted in forced curtailment to some portion of the customer load. The forced curtailment would have an expected duration of several days up to three weeks, resulting in potential customer agricultural crop loss due to lack of irrigation. In discussions with the customer, they indicated that they would not willingly accept the ongoing risk of forced curtailments. This alternative was rejected as not meeting the customer's load service requirements.

XIV. CONCLUSION

Q. Please summarize your recommendation to the Commission.

A. I recommend that the Commission determine that the projects stated above will provide benefits to Oregon customers and are therefore prudent and in the public interest.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/1001
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Richard A. Vail

Aeolus to Bridger/Anticline 500 kV Transmission Project

February 2020

Energy Vision 2020 Wind Network Improvements

D.2 Project Facilities:

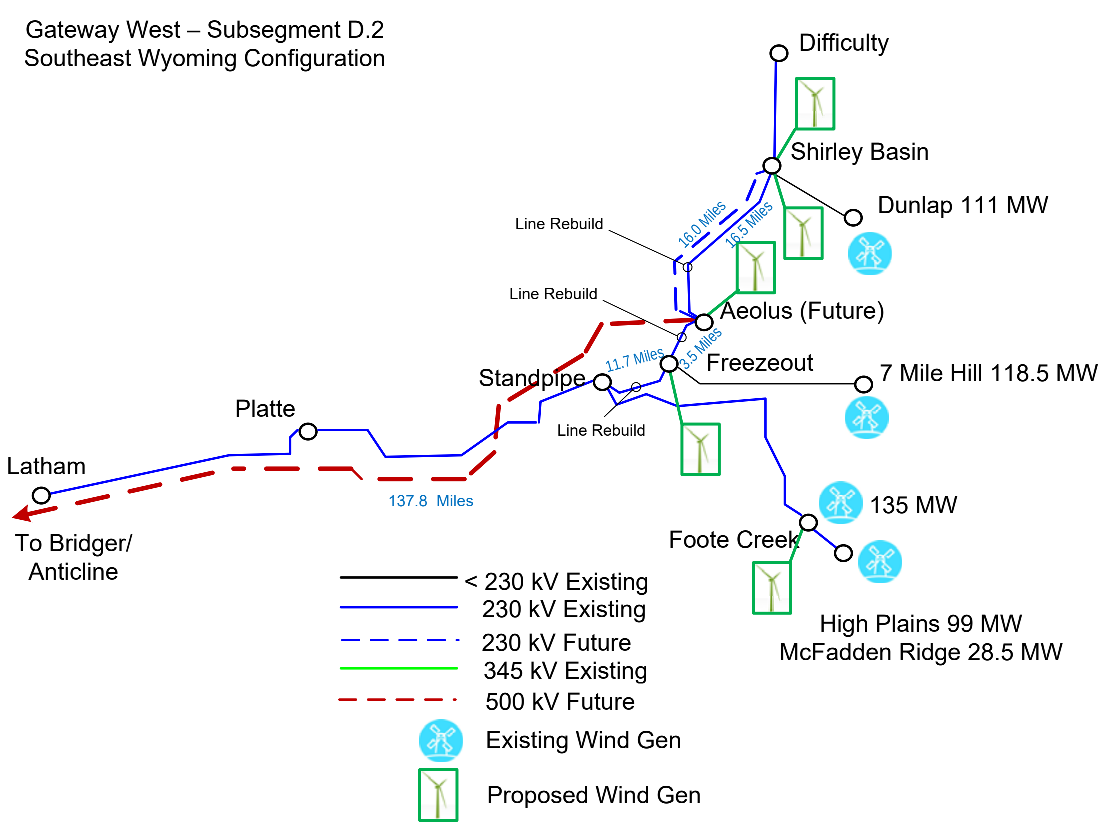
D.2 Project Transmission Facilities:

- Addition of the Aeolus 500/230 kV autotransformer
- Addition of the Aeolus – Anticline 500 kV line (~138 miles)
- Addition of the Anticline 500/345 kV autotransformer
- Addition of the Anticline – Bridger 345 kV line (5 miles)

Southeast Wyoming – Network Upgrades

- Loop the Shirley Basin – Freezeout 230 kV line into Aeolus 230 kV
- Add the Aeolus – Shirley Basin 230 kV #2 line (~16 miles) [Q0707]
- Rebuild the Aeolus – Shirley Basin 230 kV #1 line (~16 miles) [Q0712]
- Rebuild the Aeolus – Freezeout - Standpipe 230 kV line (~15 miles) [Q0712]
- Add Latham SVC

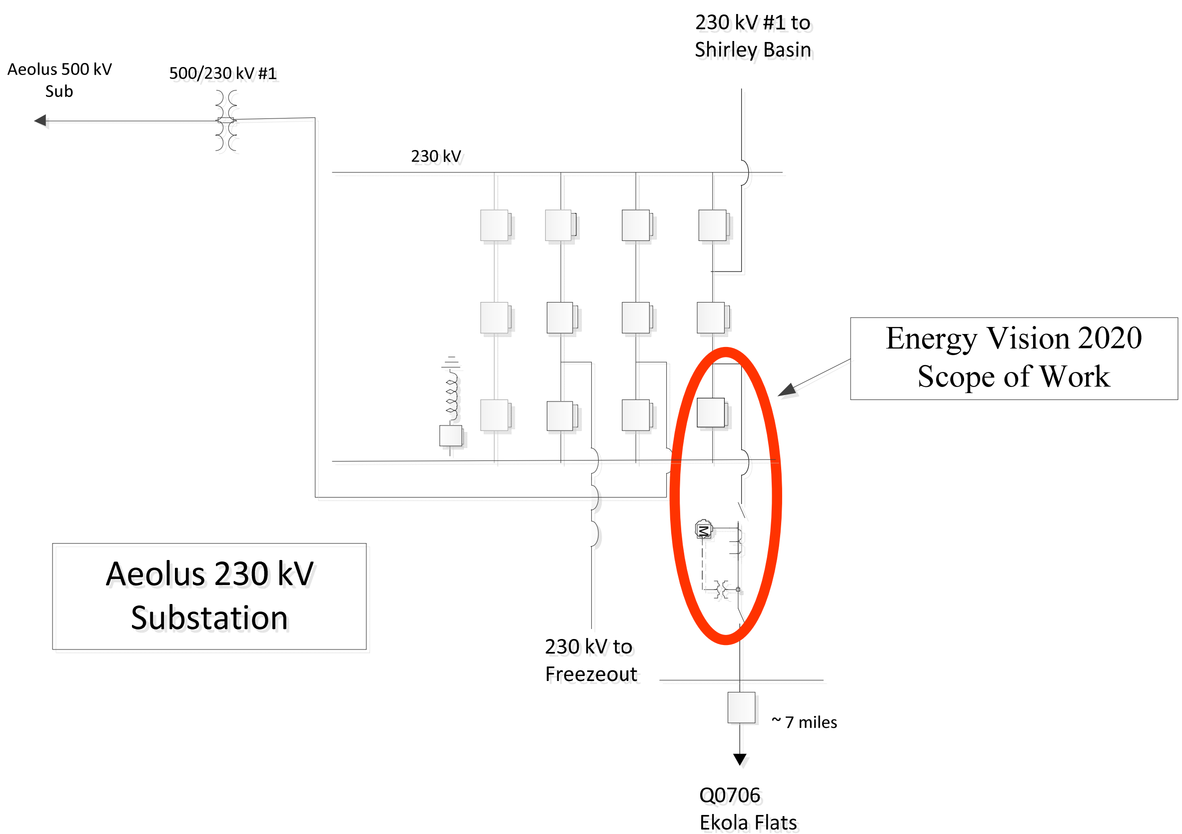
A drawing depicting all new D.2 Project network transmission facilities east of Jim Bridger Power Plant is provided below:



Updated: November 8, 2019
Contributors: Robyn Kara, Craig Quist, Kris Bremer

At the Aeolus substation to support the Ekola Flats wind project the following network upgrades are required:

- Add one (1) 230 kV 4000 ampere circuit breaker and one line position with associated switches.
- Include the project in the Aeolus RAS generation dropping scheme.



Updated: November 8, 2019
Contributors: Robyn Kara, Craig Quist, Kris Bremer

At Shirley Basin substation to support the inclusion of TB Flats I wind projects, the following network upgrades are required:

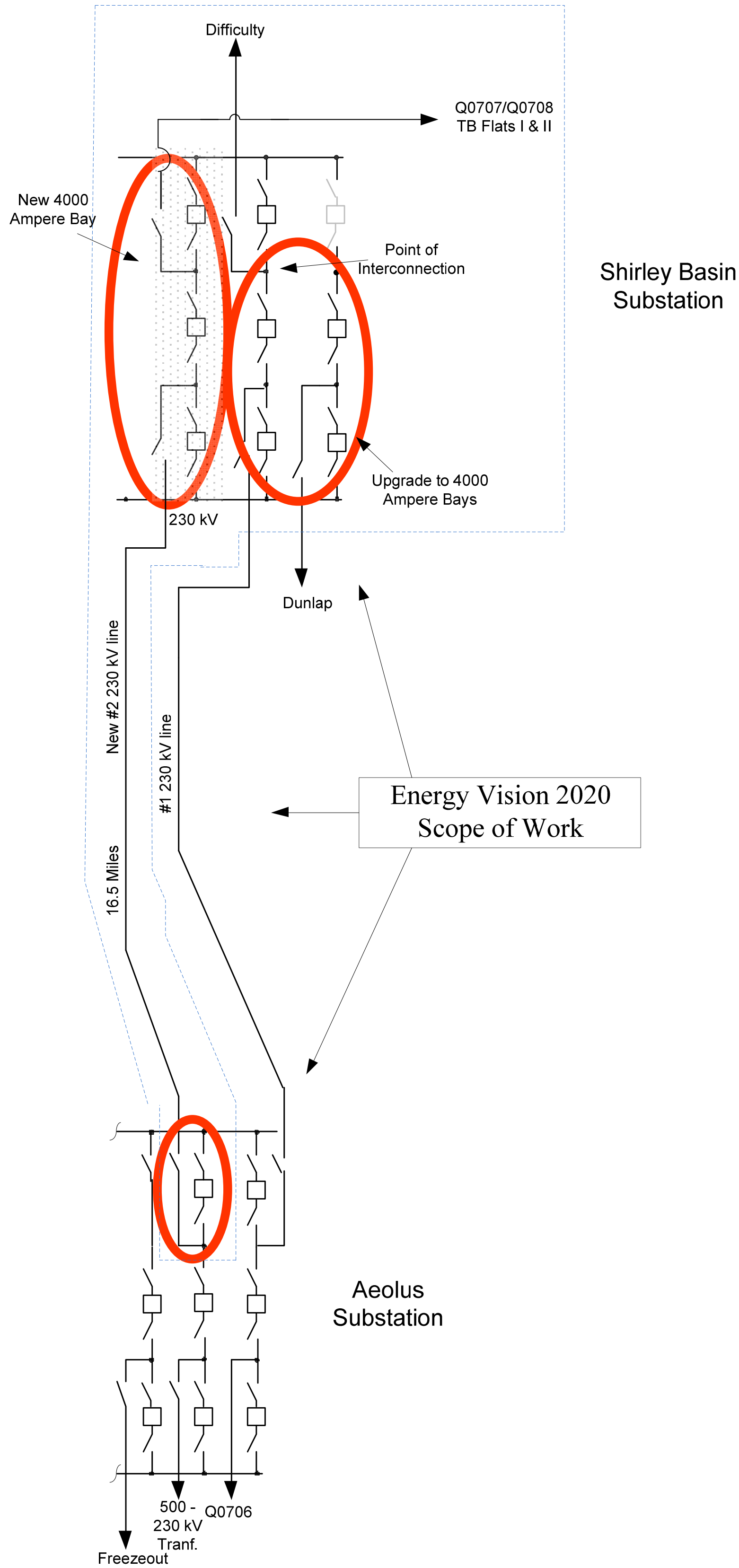
- Add one new bay and rebuild existing bays to 4000 amperes, seven (7) new 4000 ampere 230 kV circuit breakers, two line terminations with associated switches
- Construct a new approximately 16.5-mile Shirley Basin – Aeolus 230 kV #2 line.

At Aeolus substation the following network improvements are required:

- Add one (1) new 4000 ampere 230 kV circuit breaker, one line termination and associated switches
- Include the project in the Aeolus RAS generation dropping scheme.

The TB Flats I and II were combined into a single point of interconnection. As such, to support inclusion of the TB Flats II wind the following network upgrades are required:

- Include the project in the Aeolus RAS generation dropping scheme.



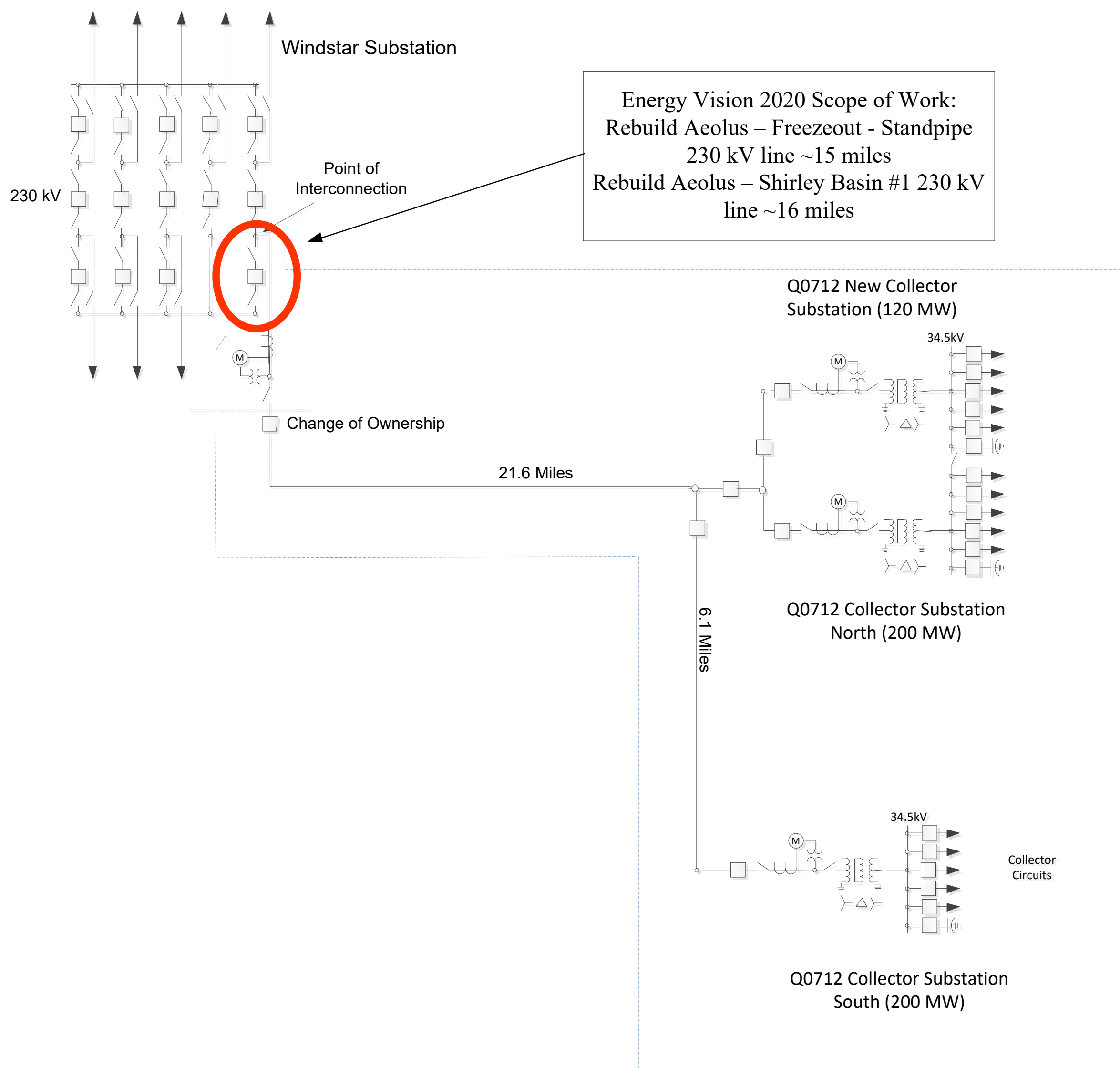
Updated: November 8, 2019
Contributors: Robyn Kara, Craig Quist, Kris Bremer

At Windstar substation to support the inclusion of Cedar Springs I wind project the following network upgrades are required:

- Add one (1) 230 kV 3000 ampere circuit breakers and one line termination

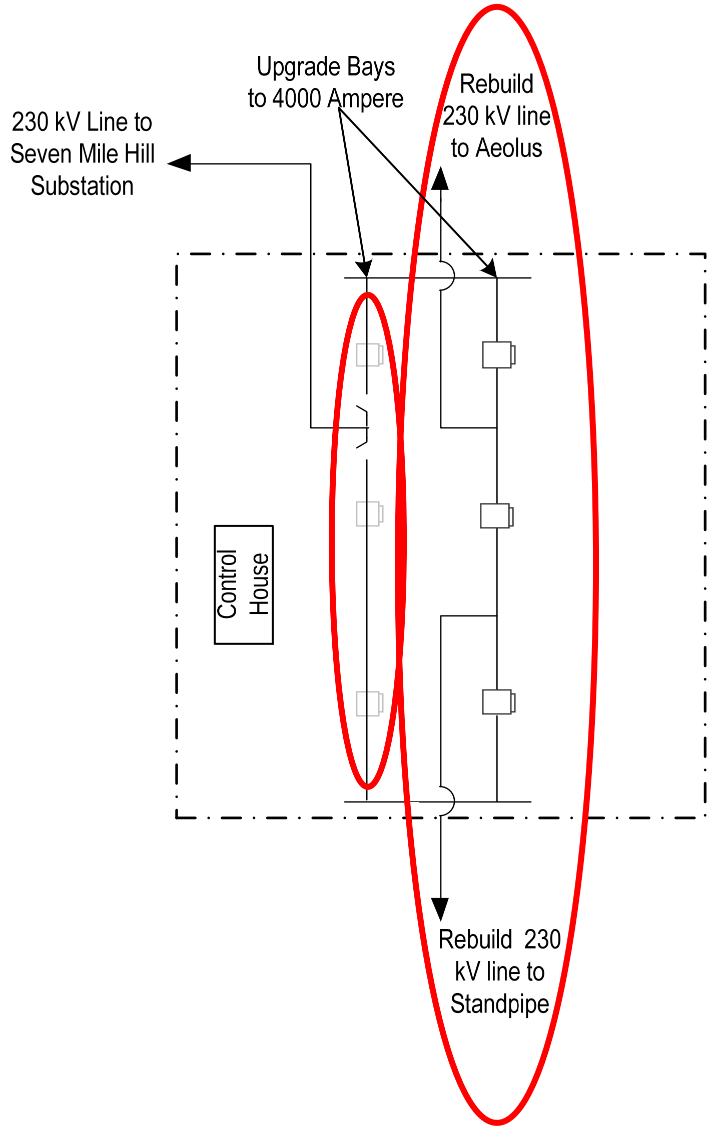
At Freezeout substation to support the inclusion of Cedar Springs I wind project the following network upgrades are required:

- Add three (3) 230 kV 4000 ampere circuit breakers along with associated switches for re-termination of lines associated with the Aeolus-Freezeout-Standpipe 230 kV line rebuild
- Upgrade two bays to 4000 amperes
- Rebuild the Aeolus – Freezeout – Standpipe 230 kV line ~15 miles
- Rebuild the Shirley Basin – Aeolus 230 kV #1 line ~16 miles



Updated: November 8, 2019
Contributors: Robyn Kara, Craig Quist, Kris Bremer

Freezeout 230 kV



Updated: November 8, 2019
Contributors: Robyn Kara, Craig Quist, Kris Bremer

Docket No. UE 374
Exhibit PAC/1002
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

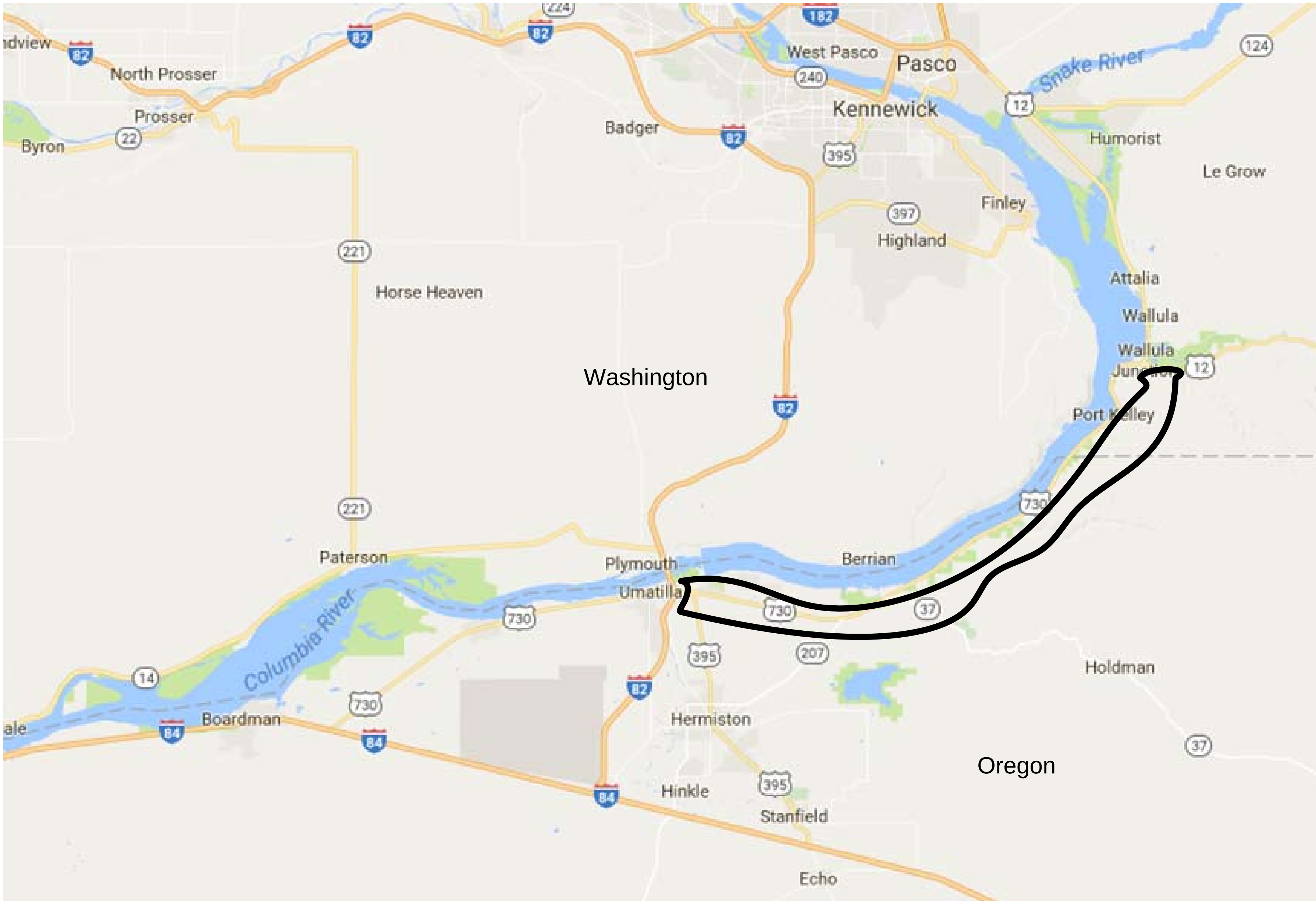
PACIFICORP

Exhibit Accompanying Direct Testimony of Richard A. Vail

Wallula to McNary 230 kV New Transmission Line Project

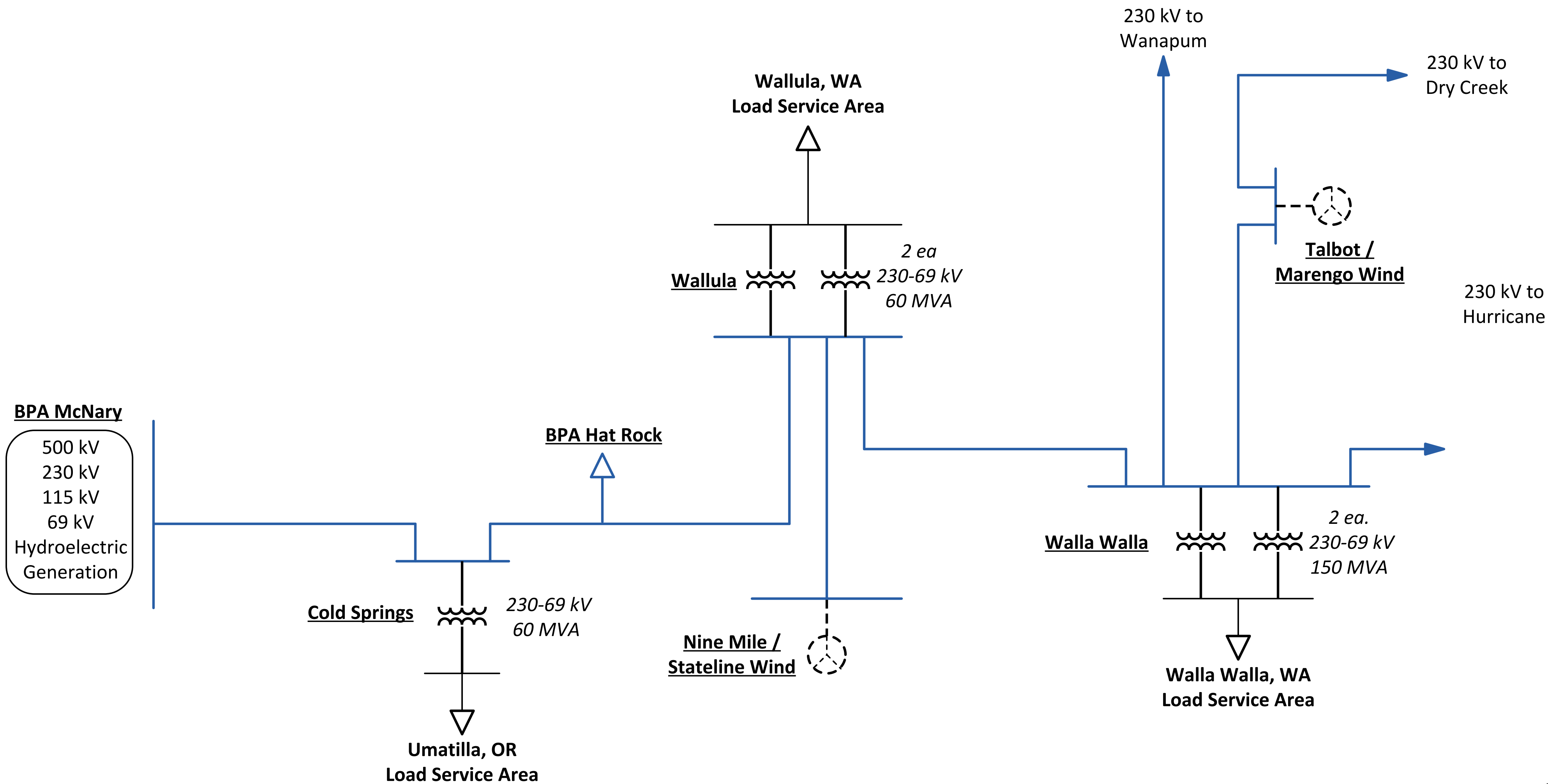
February 2020

Wallula to McNary
230 KV New Transmission Line Project Area



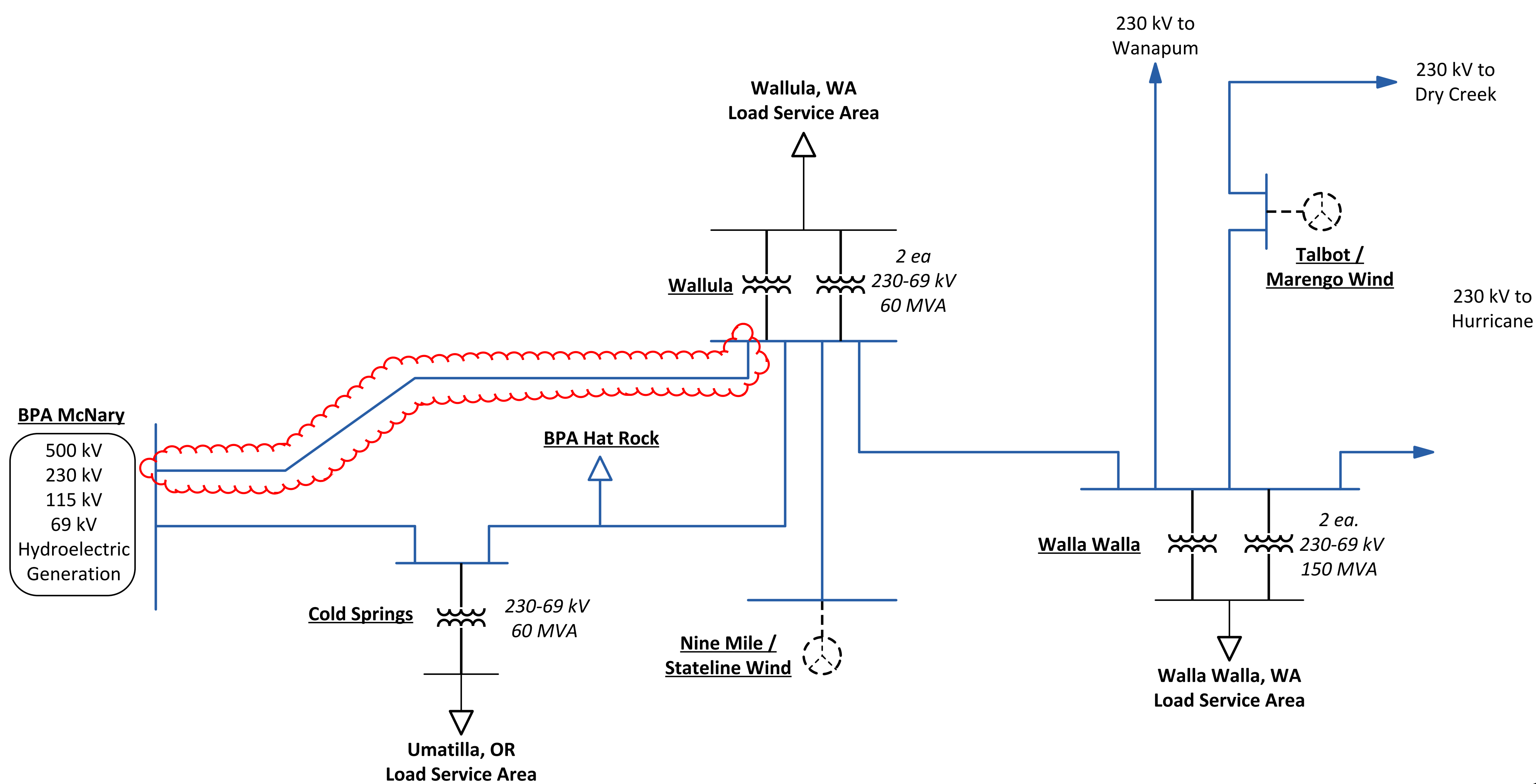
Wallula-McNary #2 Project Diagram
Pre-Project

Note: Dashes Indicate Non-PacifiCorp Facilities



Wallula-McNary #2 Project Diagram
Post-Project

Note: Dashes Indicate Non-PacifiCorp Facilities



Docket No. UE 374
Exhibit PAC/1003
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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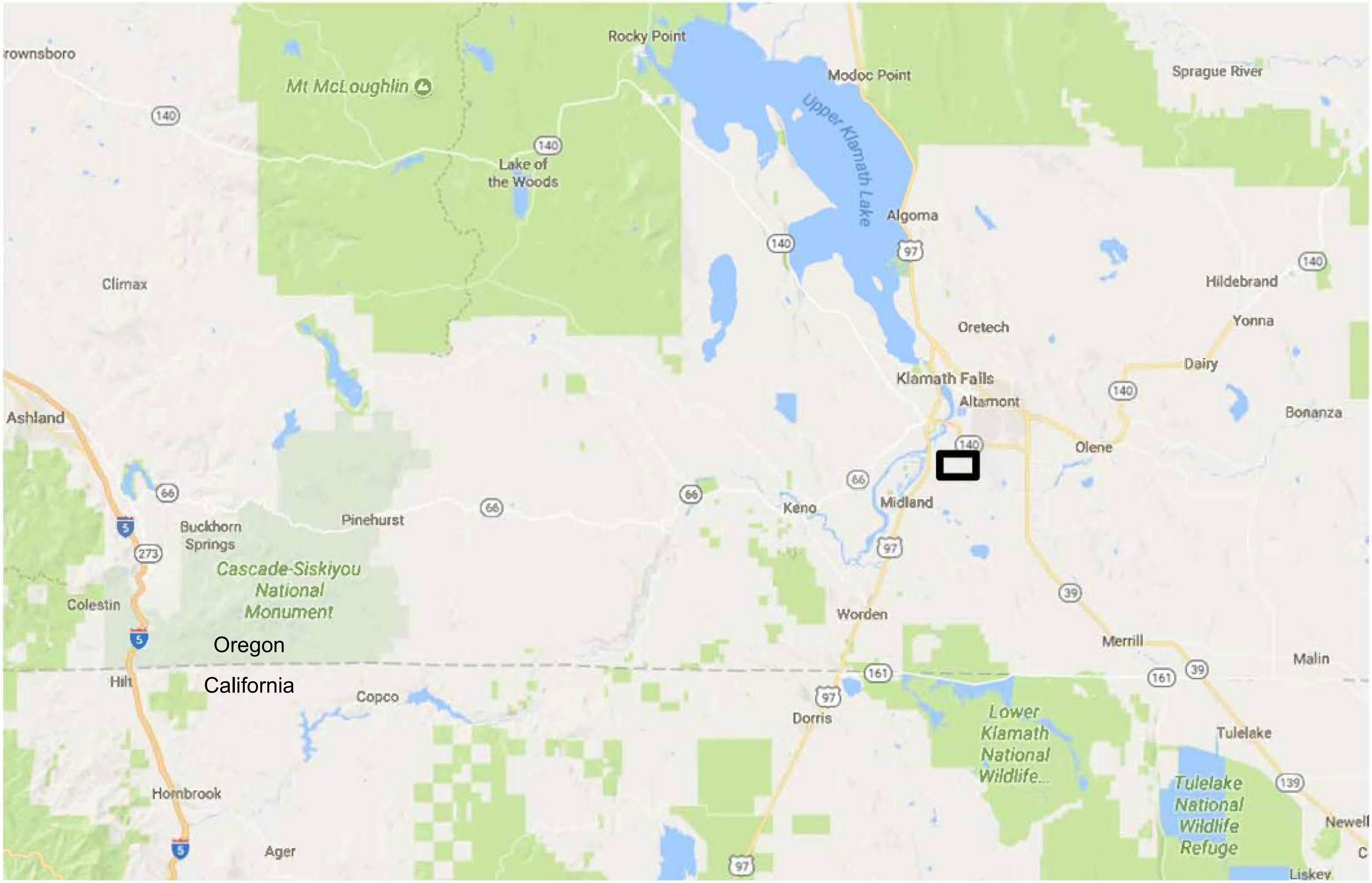
Exhibit Accompanying Direct Testimony of Richard A. Vail

Snow Goose 500/230 kV New Substation Project

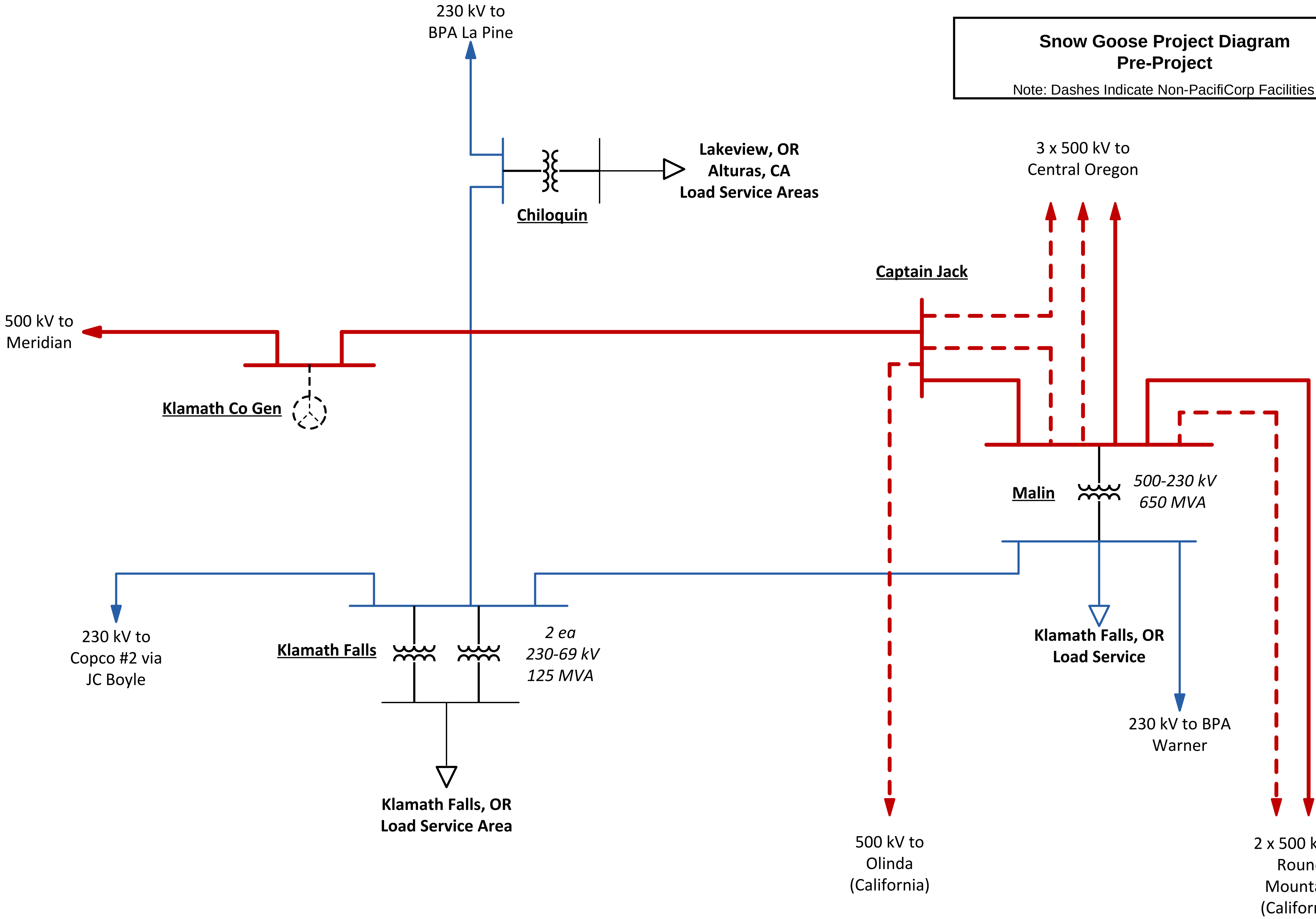
February 2020

Snow Goose 500-230 KV New Substation Project Area



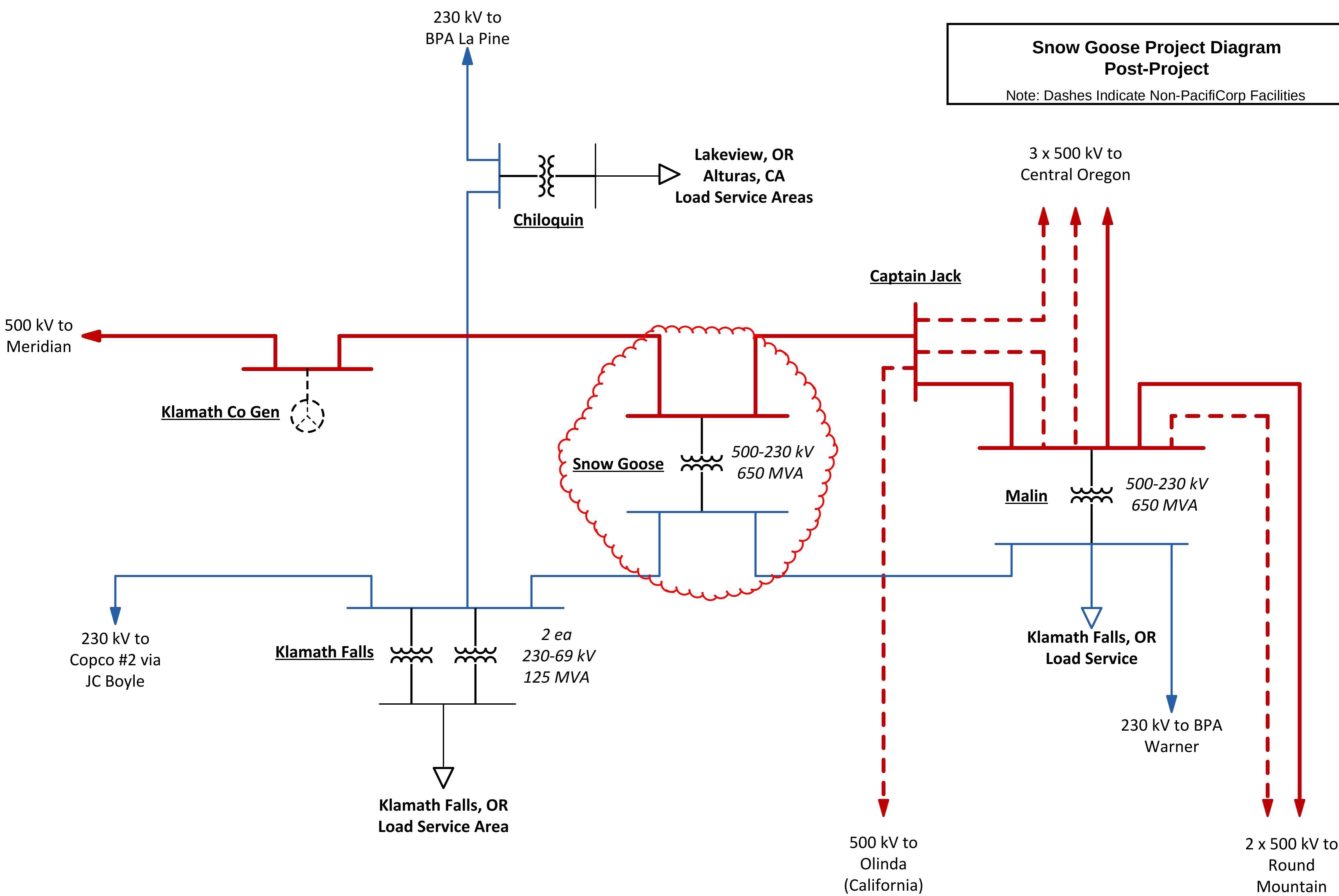
Snow Goose Project Diagram
Pre-Project

Note: Dashes Indicate Non-PacifiCorp Facilities



Snow Goose Project Diagram
Post-Project

Note: Dashes Indicate Non-PacifiCorp Facilities



Docket No. UE 374
Exhibit PAC/1004
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Exhibit Accompanying Direct Testimony of Richard A. Vail

Vantage to Pomona Heights 230 kV New Transmission Line Project

February 2020

Vantage to Pomona Heights
230 KV New Transmission Line Project Area

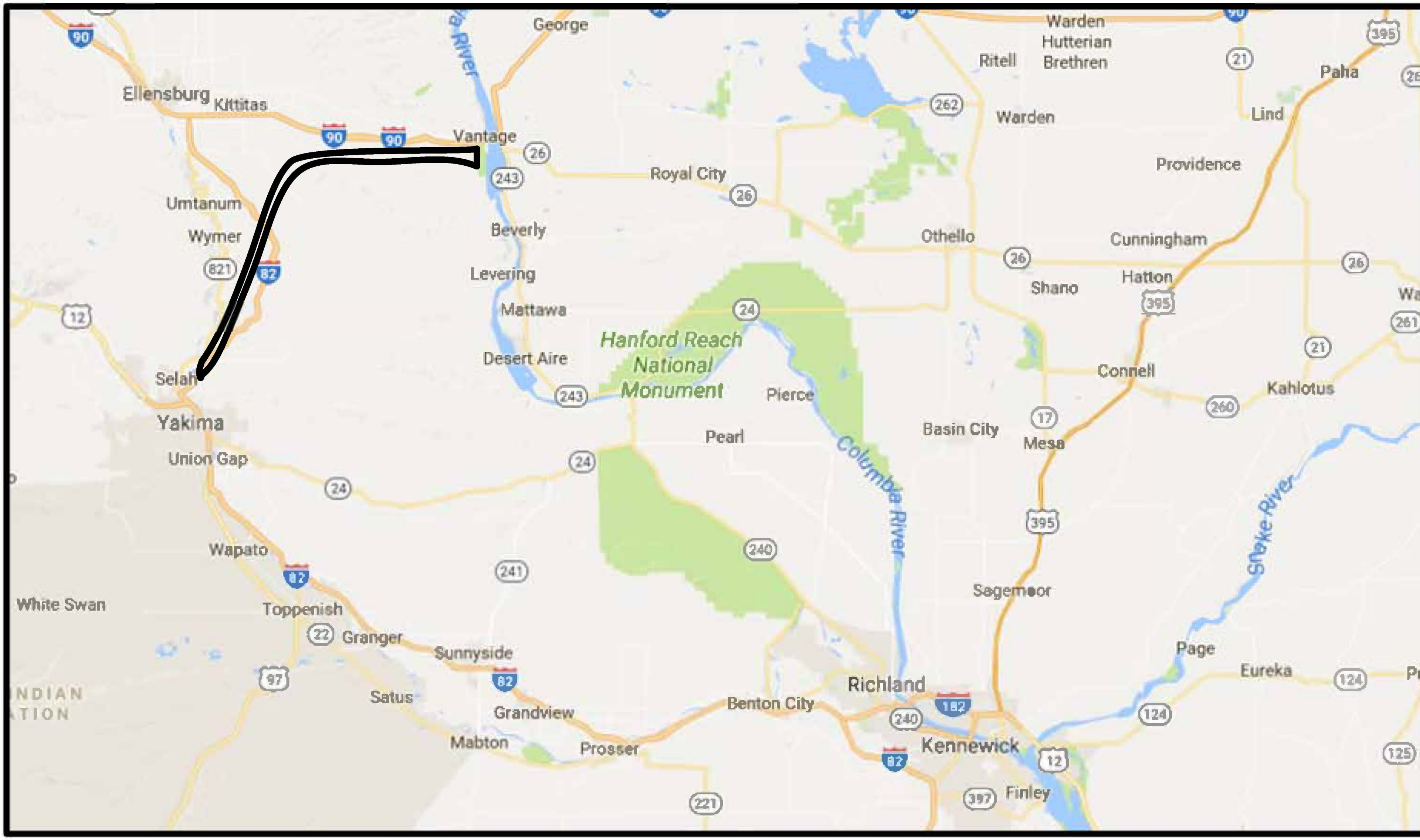
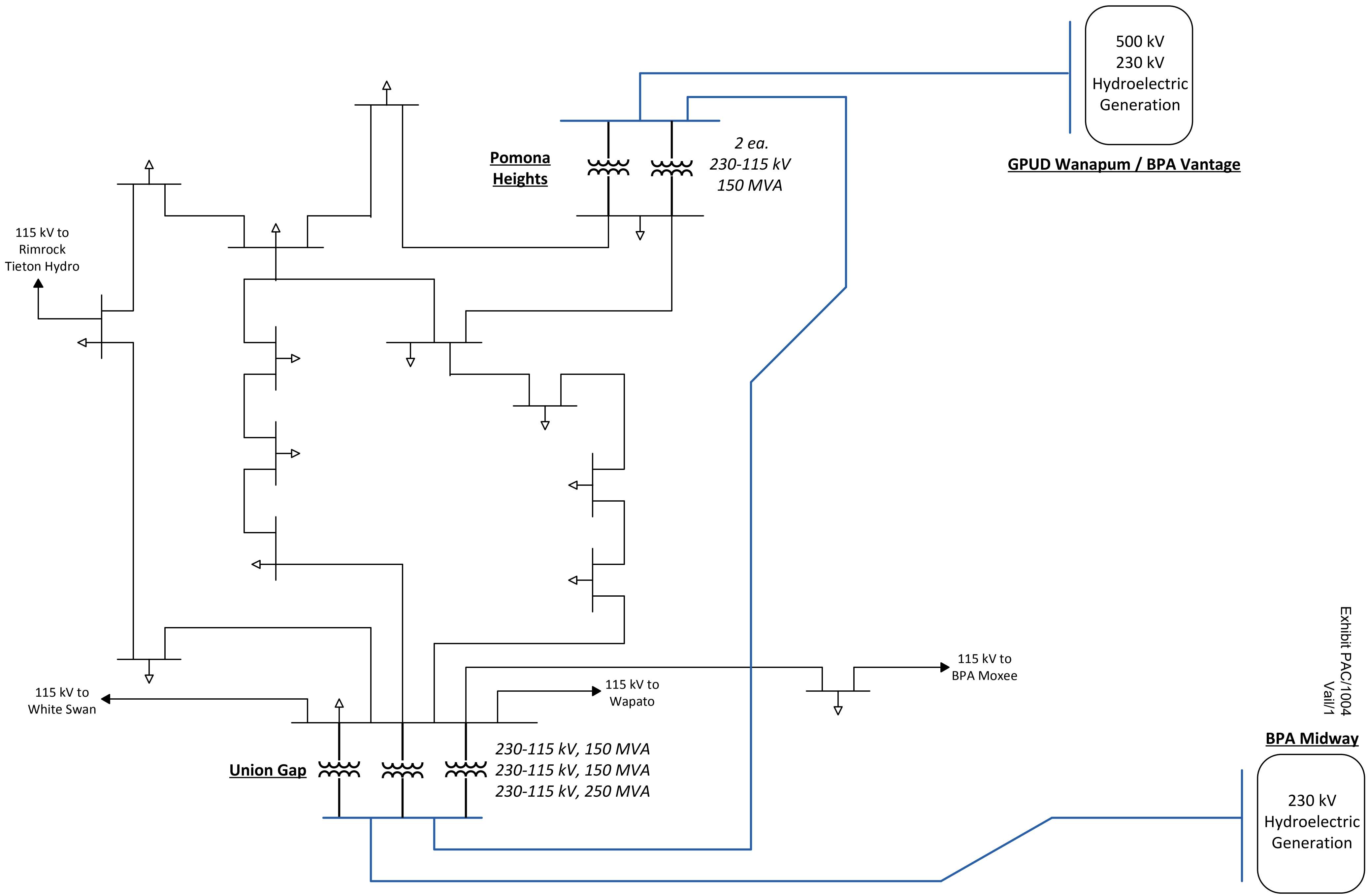
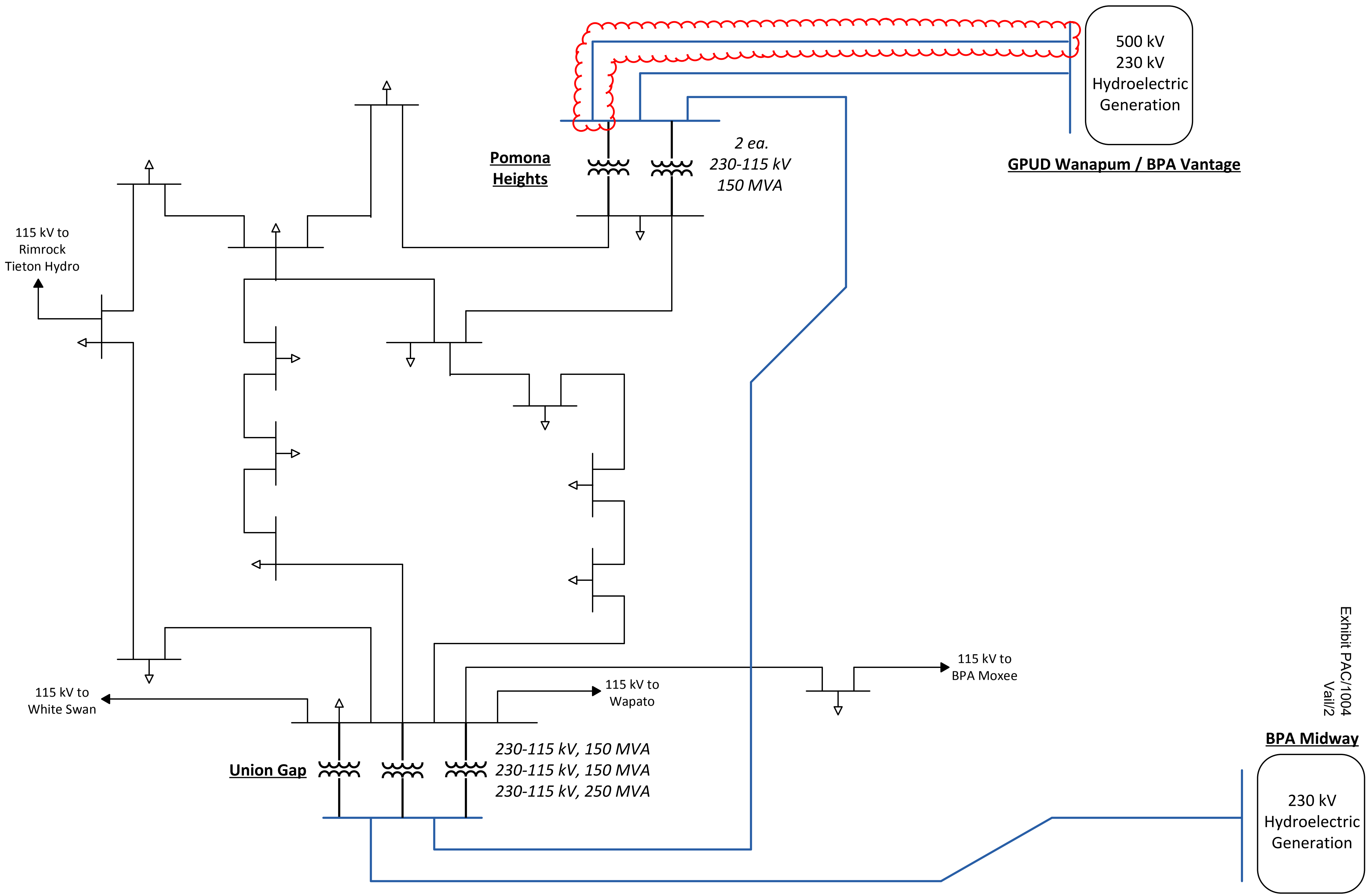


Exhibit PAC/1004
Vail/1

Vantage to Pomona Heights Project Diagram
Pre-Project



Vantage to Pomona Heights Project Diagram
Post-Project



Docket No. UE 374
Exhibit PAC/1005
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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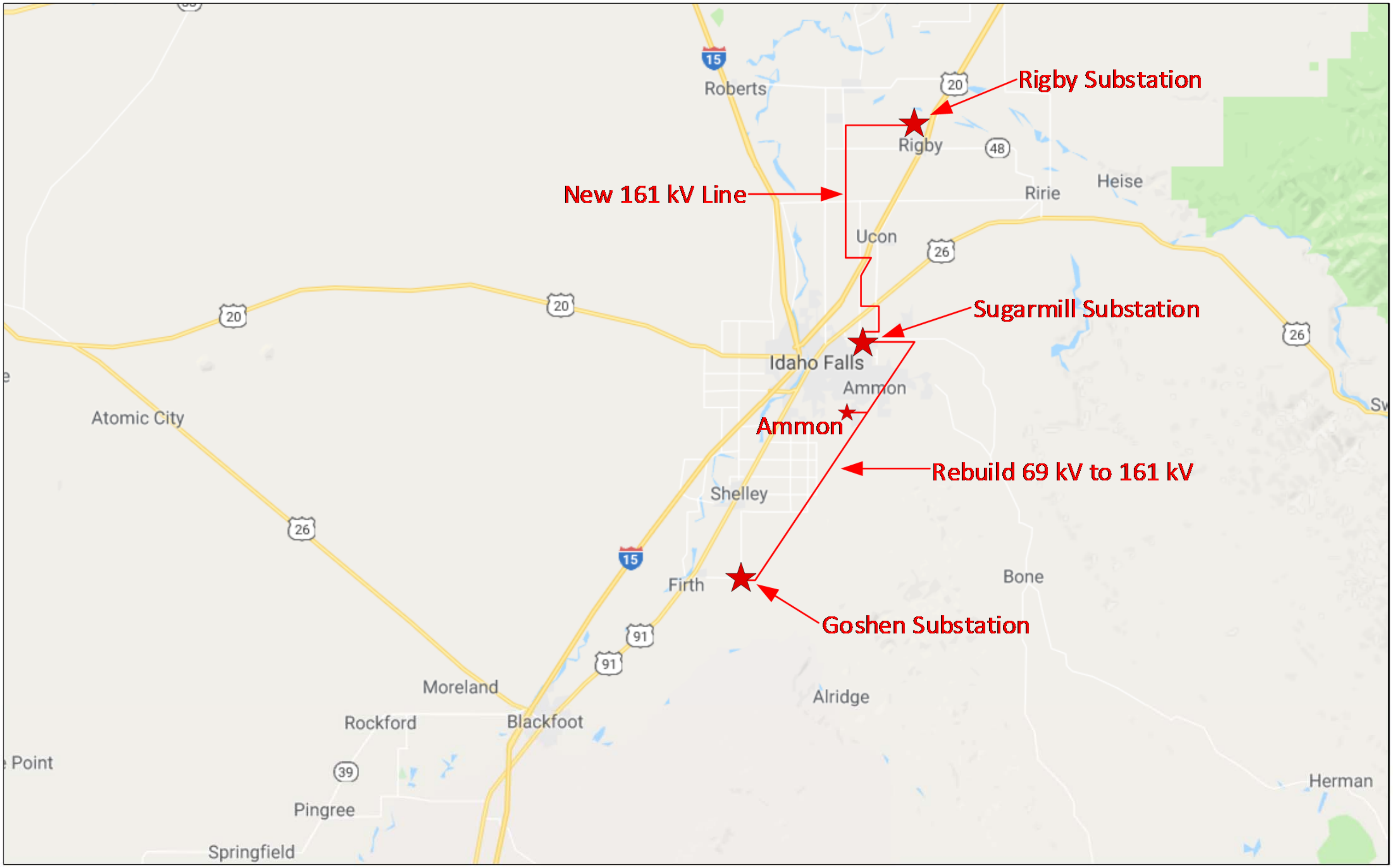
Exhibit Accompanying Direct Testimony of Richard A. Vail

Goshen to Sugarmill to Rigby 161 kV Transmission Line Project

February 2020

Goshen-Sugarmill-Rigby
161 KV Transmission Line Project Area



Docket No. UE 374
Exhibit PAC/1006
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Exhibit Accompanying Direct Testimony of Richard A. Vail

Sigurd to Red Butte 345 kV Transmission Line Project

February 2020

Exhibit PAC/1006
Vail/1

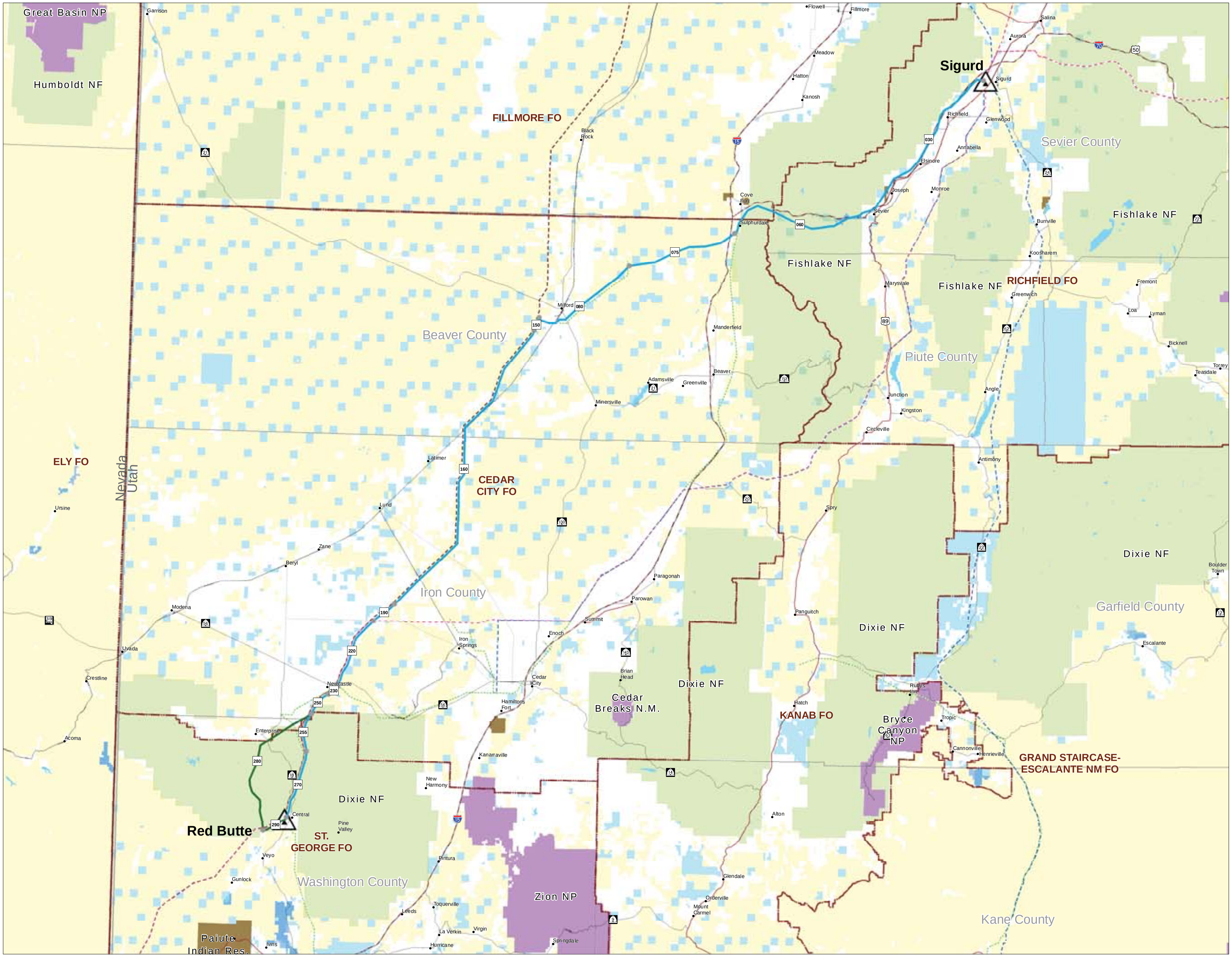


FIGURE 1-1
PROJECT AREA

Legend

- Proposed Route
- Alternatives To Be Considered
- Existing Substation
- Link Node
- Link ID #

JURISDICTIONS

- Bureau of Land Management
- Indian Reservation
- U.S. Forest Service
- National Park Service
- U.S. Fish & Wildlife Service
- Department of Defense
- Bureau of Reclamation
- State Land
- Private Land
- State Park
- BLM District/Field Office
- Lake
- County
- City

EXISTING FACILITIES

- 500kV+/- DC Transmission Line
- 500kV Transmission Line
- 345kV Transmission Line
- 230kV Transmission Line
- 115/138kV Transmission Line

OTHER EXISTING LINEAR FACILITIES

- Interstate Highway
- US Highway
- State Highway
- Railroad

SOURCES:
Land Ownership, AGRC/Idaho DWR/U of Wyoming, Colorado BLM; Transmission Lines and Substations, PacifiCorp

NOTE:
Transmission systems and substation locations are schematic and do not necessarily represent accurate locations.

December 24, 2008

0 2 4 8 12 Miles

DRAFT

SIGURD TO RED BUTTE No. 2
345kV TRANSMISSION LINE

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P:\GIS\Projects\PacifiCorp\sigurd_red_butte_No.2_345kV\mxds\GWS_Sigurd_RedButte_Base.mxd

Docket No. UE 374
Exhibit PAC/1007
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

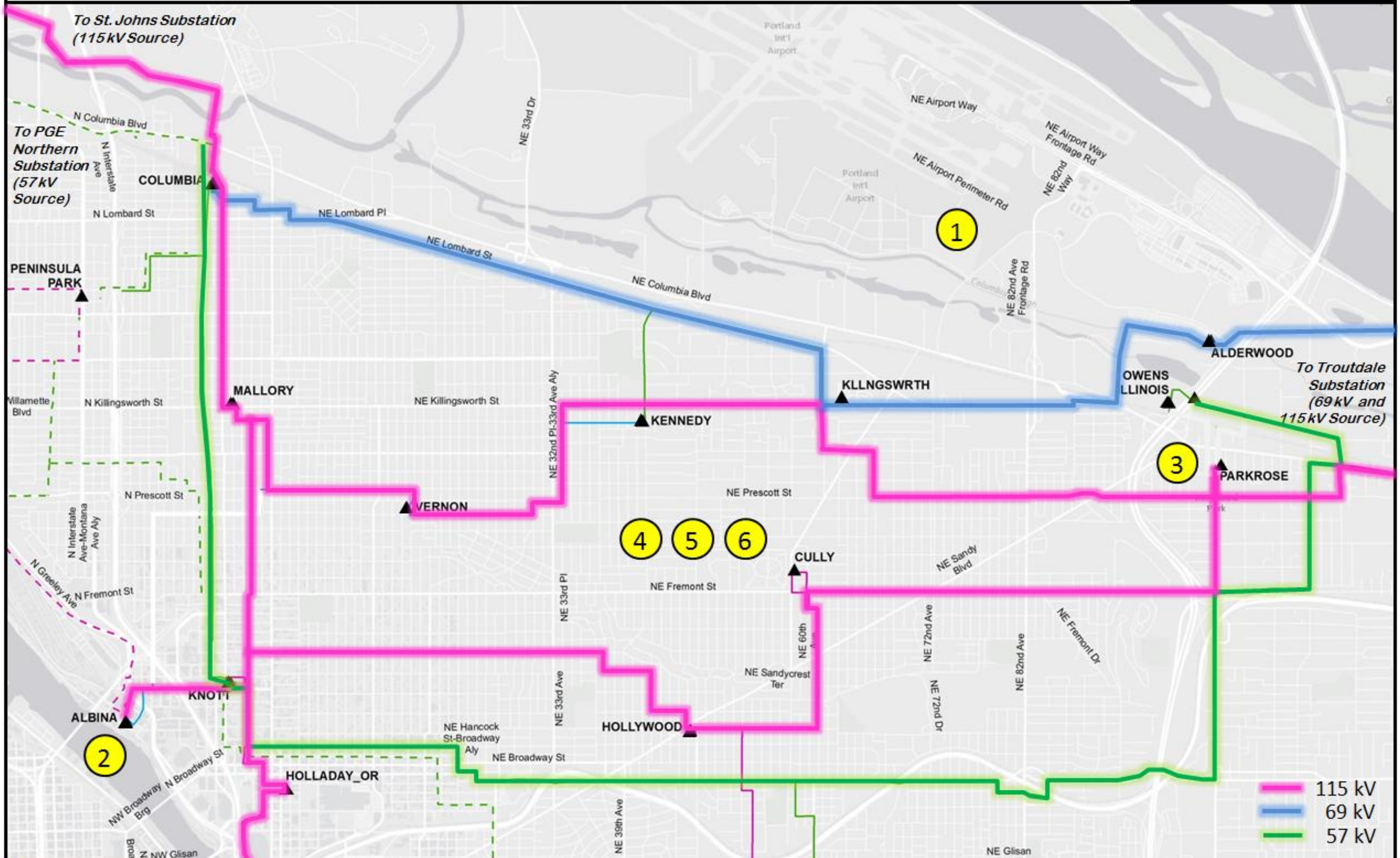
Exhibit Accompanying Direct Testimony of Richard A. Vail

Northeast Portland Transmission Upgrade Project

February 2020

NE Portland Conversion Project

AFTER



BENEFITS

1) Airport now has independent transmission sources
2) Albina aging assets reliability risk mitigated
3) Parkrose: Removal of the last 57kV supplied sub for Pacific Power, mitigating lack of mobile and spare transformer risks.
4) Reliability improvement due to increased transfer capability
5) Remediation of multiple existing and future TPL deficiencies
6) Reduces overall operating risk in the Portland area while increasing the ability to meet known spot load growth additions.

Docket No. UE 374
Exhibit PAC/1008
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

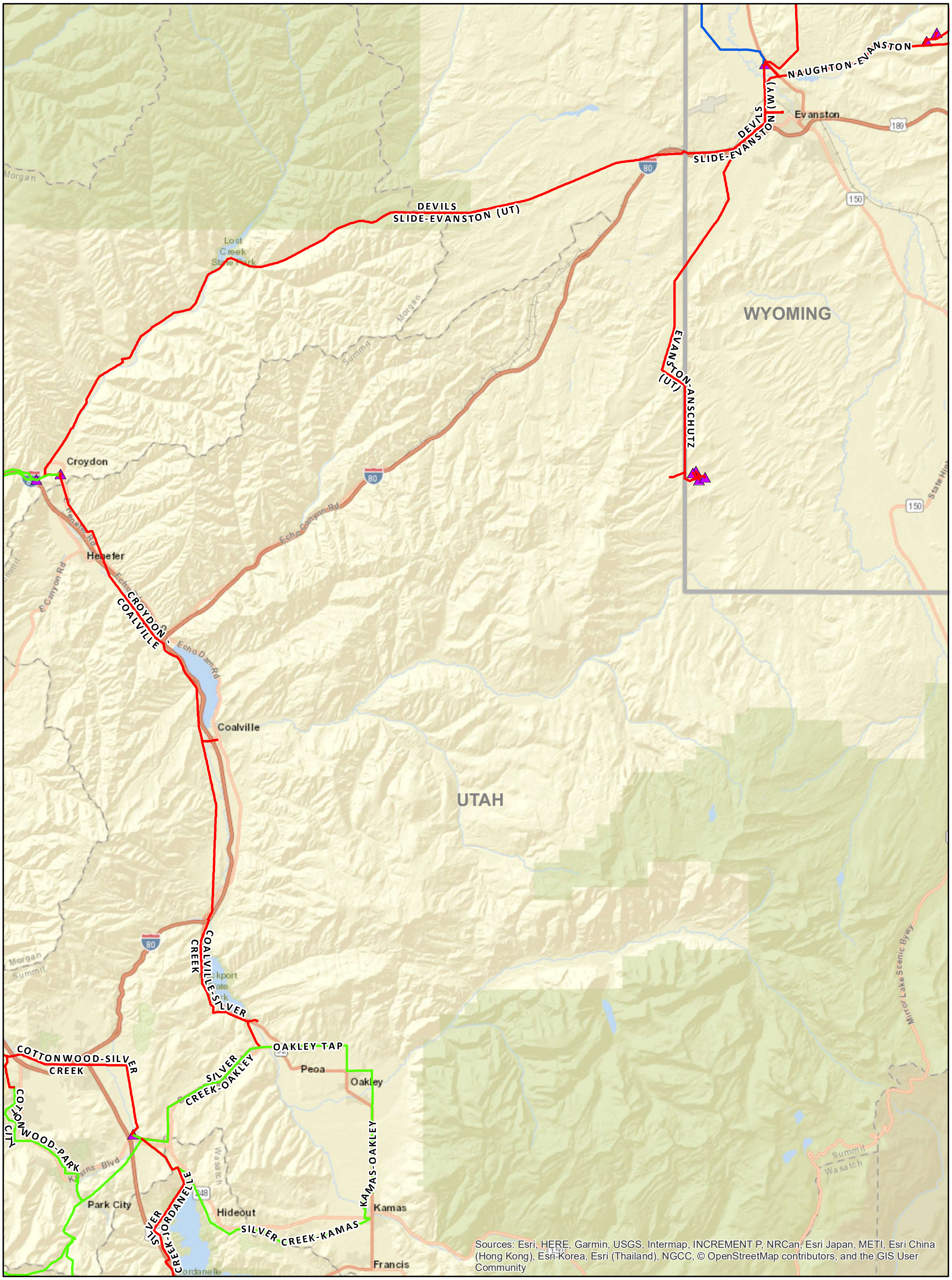
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Richard A. Vail

Southwest Wyoming Silver Creek 138kV Transmission Line Project

February 2020



Southwest Wyoming to Silver Creek 138kv Transmission Line

Legend

Transmission Line

Voltage (kV)

- 46 kV
- 138 kV
- 230 kV
- Transmission Substation
- State Boundary

0 0.5 1 2 Miles

N

PACIFICORP
GIS SUPPORT SERVICES
Solutions Group
gisdept@pacificorp.com

Data is projected in UTM Zone 12, NAD83, meters.

PacifiCorp makes no representations or warranties as to the accuracy, completeness or fitness for a particular purpose with respect to the information contained in this map. PacifiCorp shall have no responsibility or liability to any person or entity resulting from the use of any information furnished in this map.

Docket No. UE 374
Exhibit PAC/1009
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

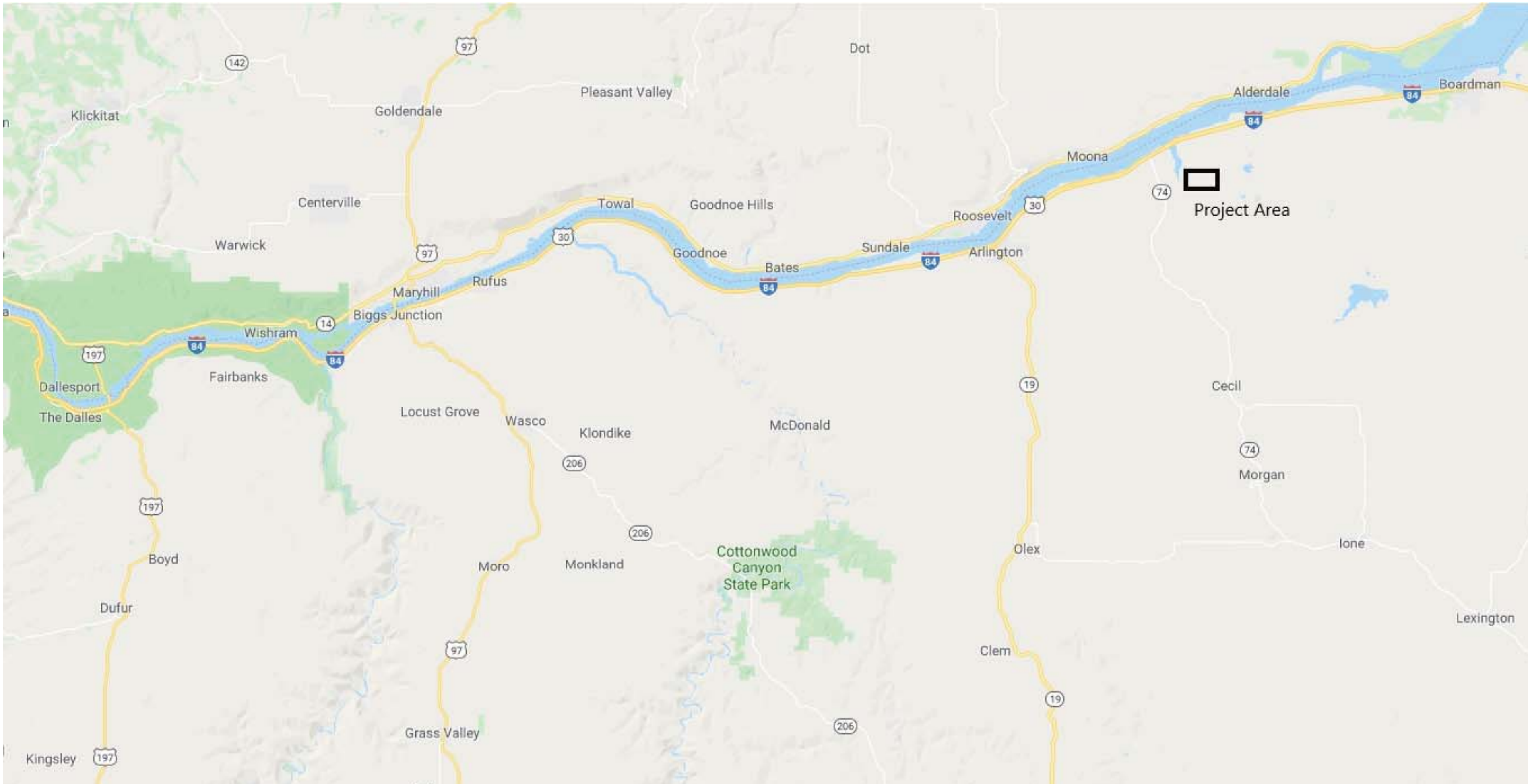
PACIFICORP

Exhibit Accompanying Direct Testimony of Richard A. Vail

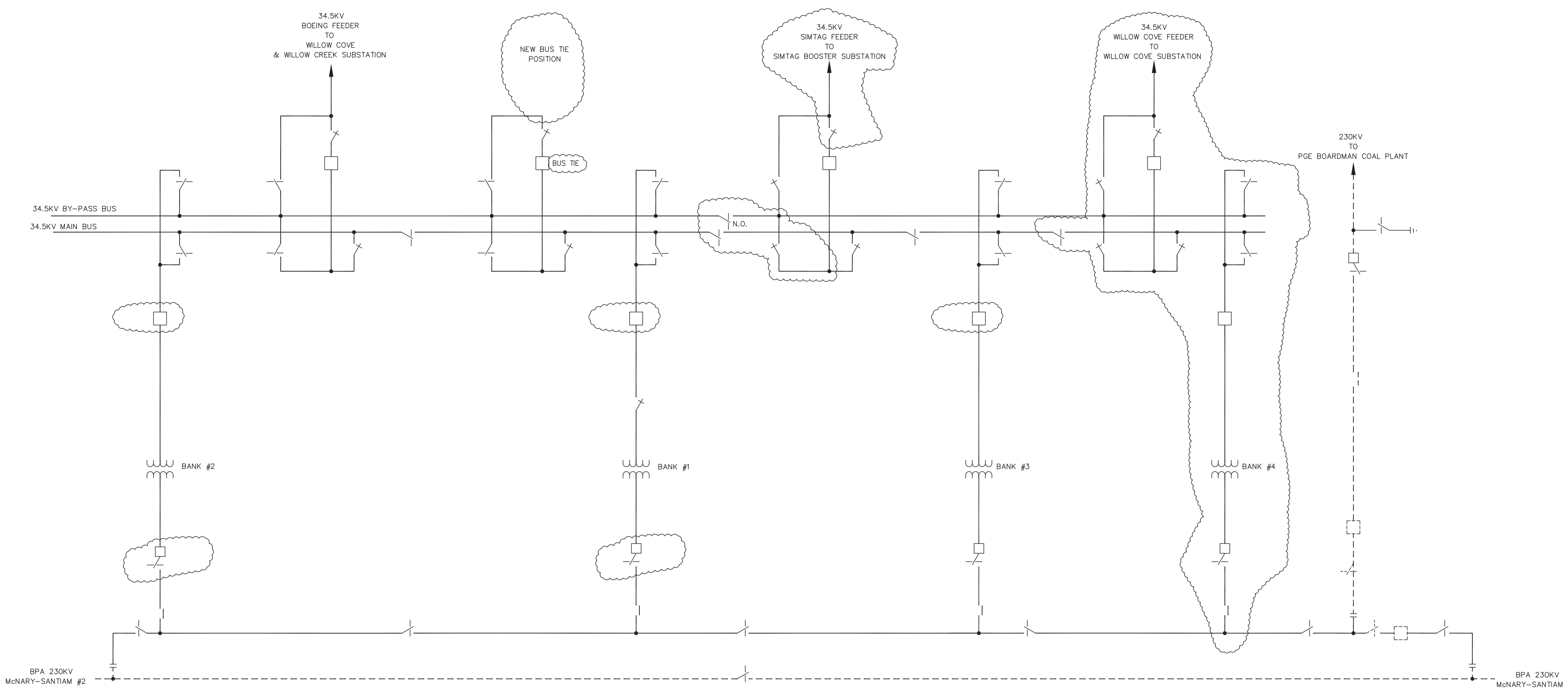
Threemile Canyon Farm Project

February 2020

Threemile Canyon Farm 2,500 HP Increase - Project Area Map



Threemile Canyon Farm 2,500 HP Increase - Dalreed Substation Project Diagram



Docket No. UE 374
Exhibit PAC/1100
Witness: David M. Lucas

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of David M. Lucas

February 2020

TABLE OF CONTENTS

ATTACHED EXHIBITS

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 David M. Lucas. My business address is 825 NE Multnomah Street, Suite 1700, Portland, Oregon 97232. My present position is Vice President of Transmission and Distribution Operations for the Company's Pacific Power division. I am responsible for the operations, maintenance, construction, safety, and support organizations for PacifiCorp's transmission and distribution systems in California, Oregon, and Washington.

Q. Briefly describe your education and professional experience.

A. I joined PacifiCorp in 2010 in the role of Managing Director of Gas and Geothermal Generation with responsibility for the operations, maintenance, and construction of PacifiCorp's natural gas and geothermal generation facilities. I held that position until I was appointed to my present position as Vice President of Transmission and Distribution Operations in November 2017. Before starting my career at PacifiCorp, I held a number of positions of increasing responsibility over a period of 20 years within the generation organization of CalEnergy Generation U.S., including the position of General Manager, U.S. Gas Operations.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe PacifiCorp's investment in certain transmission and distribution assets included in this rate case.

Q. What specific transmission and distribution system investments are you addressing in this case?

A. In addition to addressing PacifiCorp's wildfire mitigation investments, my testimony addresses the following specific projects:

- Delta fire damaged transmission facilities rebuild (Line 14 and Line 2);
- The Portland Low Voltage Secondary Network (LVSN) Project; and
- Oregon Advanced Metering Infrastructure (AMI) installation.

My testimony supports the Company's incremental investments in wildfire mitigation to address the risks posed by the increased frequency, severity and costs of wildfires to customers, employees, and Company facilities. My testimony also supports the Company's investments in the specific projects described above as prudent and in the public interest.

III. WILDFIRE MITIGATION PROJECTS

Q. Have the risks associated with wildfires changed in PacifiCorp's service territories?

A. Yes. There has always been some degree of wildfire risk across PacifiCorp's territories, including in Oregon. This risk is inherent to operating an electric utility, and is elevated for utilities in the Western United States where climates are arid year-long in some areas, or seasonally in others. However, the frequency, severity, and costs of catastrophic wildfires are increasing across the West. California's recent experiences with catastrophic and tragic wildfires, has resulted in an even greater focus on wildfire risk mitigation by public utilities. The widely publicized impact of these fires on California's public utilities has led to an increased focus on wildfire risks in PacifiCorp's service territories in California and other states, including Oregon. Evidence of this increased risk and focus on wildfires has had measurable impacts on the insurance market as "insurers have become concerned about the growing liability risks to utilities, and prices have increased substantially."[1]

Q. How is PacifiCorp addressing this increased risk profile?

A. PacifiCorp is adapting to the changes in wildfire risk through adoption of accelerated and enhanced wildfire mitigation measures that meet new industry best practices, largely derived from the experiences of California, for utility wildfire mitigation. PacifiCorp identified key goals to help inform its wildfire mitigation approach: 1) minimize the risk of wildfires from PacifiCorp equipment; 2) promptly address any problems attributed to PacifiCorp equipment if they do occur; 3) be prepared to address wildfires from other sources; and 4) respond when a wildfire puts utility equipment at risk. PacifiCorp took these goals and engaged in an extensive modeling process to develop a risk-based approach to achieving them. This risk-based approach facilitates smart investments targeted to places on PacifiCorp's system where they will have the most impact, and ensures that PacifiCorp's human capital is also deployed in areas where they will have the greatest impact. These targeted investments are incremental to PacifiCorp's investment in the ordinary course of its business, and will meaningfully reduce the wildfire risk on the Company's system.

[1] Carolyn Kousky, Katherine Greig & Brett Lingle, *Financing Third Party Wildfire Damages: Options for California's Electric Utilities*, Wharton Risk Management and Decision Process Center (Feb. 2019) *available at* https://riskcenter.wharton.upenn.edu/wp-content/uploads/2019/02/Financing-Third-Party-Wildfire-Damages-1.pdf.

Q. Please describe how the risk of wildfire has been modeled in PacifiCorp's service territory.

A. PacifiCorp recognizes that if certain weather and fuel conditions are present, a disruption of normal operations on the electrical network, called a "fault", can result in the ignition of a fire. Under certain weather conditions and in the vicinity of wildland fuels, such an ignition can grow into a harmful wildfire, potentially even growing into a catastrophic wildfire causing great harm to people and property. PacifiCorp's risk analysis reviews fire history, the recorded causes of the fires, the acreage impact of the fires, and when in the year the fires typically occur. Using that information, the risk analysis identifies the logic for a risk-informed method to strategically address utility wildfire risks. PacifiCorp patterned its wildfire risk modeling on the methodology developed after a long and iterative process in California. To take advantage of the experience learned through that process, PacifiCorp engaged REAX Engineering Inc., a fire-science engineering firm, to identify areas of elevated wildfire risk, designated as Fire High Consequence Areas (FHCA).

The data and process used in PacifiCorp's analysis are as follows:

1) Topography of the land, including elevation, slope, and aspect;

2) Fuel data which quantify fuel loading, fuel particle size, and other quantities needed by fire models to calculate the rate of spread;

3) Weather Research and Forecasting, which is a hybrid of weather modeling and surface weather observations (including temperature, relative humidity, wind speed/direction, and precipitation);

4) Historical fire weather days spanning the period from January 1, 1979, through December 31, 2017;

5) Estimated live fuel moisture;

6) Ignition modeling, using Monte Carlo simulated ignition scenarios; and

7) Fire spread modeling.

A final confirmation exercise was completed by evaluating the FHCA against historical fire perimeters (which are the final recorded footprint for any given fire), existing Company facility equipment, and the Company's service territories. The resulting FHCA, with wildfire perimeters, and PacifiCorp's service territories are shown in Exhibit PAC/1101. In general, if population density did not correlate to fuel and fire weather history, it would not be considered a candidate for FHCA designation.

Q. Based on this wildfire risk modeling, what components of PacifiCorp's system have been identified as existing in a FHCA?

A. Based on the wildfire risk modeling conducted in PacifiCorp's service area, a large portion of PacifiCorp's service territory in southern Oregon, northern California and parts of Washington and Utah are identified as having sections inside the FHCA and are candidates for wildfire mitigation project investments.

Q. What are the costs for the wildfire mitigation projects in 2019 and 2020?

A. Table 1 below describes the specific wildfire mitigation costs by breakdown of activity.

Table 1: Wildfire Mitigation Program Capital Costs*

Mitigation Program	Description	Purpose/Risk Being Mitigated	Category	2019 Capital Costs	2020 Capital Costs	2021 Capital Costs	2022 Capital Costs
System Hardening	Distribution line rebuilds including all or parts of the following: installation of covered conductor, pole replacements, wrapping wood poles in fire proof mesh, and conductor replacements	Reduce equipment failure that may ignite a wildfire along with increased resiliency to a wildfire occurrence	Oregon Distribution	$550,000	$13,364,000	$37,991,000	$38,253,000
System Hardening	Transmission line rebuilds including all or parts of the following: installation of covered conductor, pole replacements, wrapping wood poles in fire proof mesh, and conductor replacements	Reduce equipment failure that may ignite a wildfire along with increased resiliency to a wildfire occurrence	Transmission	$35,000	$20,475,000	$34,538,900	$35,420,000
Advanced Protection and Control	Replace electromechanical 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	Oregon Distribution	$458,000	$2,330,000	$2,465,000	$1,700,000
Advanced Protection and Control	Replace electromechanical relays protecting transmission lines in FHCA with modern microprocessor relays that provide more accurate data and faster relaying	Increased ability to locate where a fault occurs on a line which contributes to improved patrol time	Transmission	$1,308,000	$4,743,000	$3,774,000	$750,000
Condition Corrections	Prioritize corrections to any deficiencies found from inspections in the FHCA	Reduce equipment failure that may ignite a wildfire along with increased resiliency to a wildfire occurrence	Transmission	$200,000	$100,000	0	0
Access Roads and Rights-of-way increases	Addition of new access roads and/or improvements along with increasing rights of way on transmission lines that the forest service wants to use as fire breaks	Reduce likelihood of equipment loss in the case of a wildfire by increasing accessibility for firefighters	Transmission	0	$1,000,000	0	0
Total				**$2,551,000**	**$42,012,000**	**$78,768,000**	**$76,123,000**

*Transmission costs are provided on a total-company basis. Oregon distribution costs are situs assigned to Oregon

I discuss these mitigation programs in more detail below.

System Hardening

Q. Please explain what system hardening is in the context of the Company's wildfire mitigation efforts.

A. System hardening is an engineered response to an identified risk to the electrical system. System hardening includes retrofitting specific devices or components within the system to make it more resilient, and may also include the wholesale replacement of legacy equipment when retrofitting is not a viable solution. I will describe some of the system hardening that PacifiCorp is and will be engaging in to mitigate wildfire risks in more detail below.

Q. How do these system hardening projects reduce the threat of wildfire?

A. PacifiCorp's system hardening projects focus on reducing the potential that the power system is the source of ignition for a catastrophic fire by creating a spark during a fault event. A significant ignition driver on electrical systems is contact from foreign objects (trees, wildlife, mylar balloons, etc.) that can result in high-energy and high-temperature arcing between two conductors or between one conductor and the ground.

Q. What hardening efforts on distribution systems reduce potential ignitions?

A. A key hardening effort for wildfire mitigation is a covered conductor program to mitigate the risk of contact related faults on overhead conductor. Covered conductor, unlike bare conductor, is designed to withstand incidental contact with vegetation, other debris, and even the ground in a wire down event. The program will involve more than replacing existing bare conductor with covered conductor. Poles will be replaced as necessary based on loading assessments of existing poles where covered conductor is to be installed. This is because, covered conductor is heavier than bare conductor, and under the combination of ice and wind has a larger diameter which results in further additional pole loading. A secondary benefit to covered conductor is an improvement in reliability. In certain applications standard overhead fuses will be replaced within the FHCA with non-expulsion fuses that eliminate any melted fuse material from falling to the ground when operated. In addition, distribution poles will be evaluated based on location within the FHCA and, if required, replaced with composite material poles to diversify the vintages (remaining strength), and reduce wildfire risk due to pole failures as wildfires burn through an area.

Q. Is it standard practice for PacifiCorp to install covered conductor, non-expulsion fuses, or composite material distribution poles?

A. No. Standard overhead circuit construction uses bare conductor and wood poles that balance safety, reliability, and costs. The installation of covered conductor, non-expulsion fuses, and composite material poles are in direct response to increased wildfire risk and are specifically designed to accelerate and improve mitigation of catastrophic wildfires associated with PacifiCorp's system.

Q. What were the Company's capital expenditures with respect to its system hardening efforts in 2019?

A. As shown in Table 1, in 2019, PacifiCorp made approximately $585,000 ($559,000 Oregon-allocated) in distribution and transmission capital expenditures for its system hardening wildfire mitigation measures.

Q. What capital expenditures will the Company make in 2020 and what does the Company forecast for 2021 and 2022 with respect to system hardening?

A. As shown in Table 1, in 2020, PacifiCorp will make capital expenditures of approximately $13,364,000 in its Oregon distribution system and $20,475,000 ($5,328,000 Oregon-allocated) in its transmission system on system hardening. PacifiCorp expenditures will further accelerate into 2021, when approximately $37,991,000 will be spent on system hardening the Oregon distribution system and $34,539,000 ($8,988,000 Oregon-allocated) on hardening the transmission system. In 2022, the Company anticipates additional expenditures of $38,253,000 to harden the Oregon distribution system and $35,420,000 ($9,217,000 Oregon-allocated) to harden the transmission system.

Q. How do transmission line rebuilds help mitigate and protect against wildfire risk?

A. Rebuilding transmission lines helps to reduce equipment failures and incidental contacts that pose a risk of wildfire ignition. Such equipment failures, while infrequent occurrences, could result in substantial arc energy that can result in wildfire ignition. Due to the cross-country nature of many portions of PacifiCorp's system (particularly on the local transmission network) the risk of ignition sources is heightened. For example, in Oregon, trees outside of the vegetation managed corridors that are particularly tall, or located on slopes, result in increased risk of fall-in contacts. Rebuilding transmission lines in areas where this risk is heightened allows PacifiCorp to install covered conductor and improve structures. Respectively, such measures will reduce the probability of a fault event and improve resiliency to the extent rebuilt structures can better withstand localized wildfire events.

Q. What criteria did the Company use to select areas in the FHCA to replace existing conductor with covered conductor?

A. PacifiCorp targeted areas within the FHCA to determine what areas in its system were at elevated risk based on proximity to population centers, historic weather patterns, and vegetation. Covered conductor was selected for use where there is risk of incidental contacts, such as large branches or trees striking the phase conductors.

Q. Are there reliable measurements or metrics the Company can use to determine how successful the use of covered conductor is in mitigating wildfire risks over time?

A. Yes, though such measurements will not be immediately informative. Over time, the Company anticipates that comparisons of fault rates resulting from incidental tree contacts for the areas where covered conductor is employed versus the same areas before replacement with the covered conductor will demonstrate the effectiveness of this measure.

Q. What kind of monitoring does the Company plan to use to ensure that the use of covered conductor is meeting expectations in the absence of such metrics?

A. As noted in my response to the preceding question, the Company will track fault rates resulting from incidental tree contacts on rebuilt sections. This information will enable the Company to compare faults both before and after installation of covered conductor to better understand how successful it has been in mitigating wildfire risks over time. Unfortunately, the data needed to quantitatively provide useful metrics for such a comparison will not be available for several years.

Q. How do pole replacements help mitigate and protect against wildfire risk?

A. Replacing wood pole structures with composite materials increases the structure's ability to withstand wildfires caused by non-utility sources, and therefore enhances the resiliency of the system. The reduced risk of a composite pole burning also reduces the risk posed by a pole failure, which could exacerbate an existing wildfire caused by another source.

Q. What criteria is the Company using to identify the poles that should be replaced?

A. The Company has developed several criteria to determine which poles to replace, including condition based information, the quantity of attachments (e.g., joint use with cable or communication providers) that could result in higher use of the available pole strength, age of the pole, its location, right of way clearances, and the existence of wildfire fuel (i.e., vegetation) in the area.

Q. Are there reliable measurements or metrics that the Company can use to determine how successful its pole replacements are in mitigating wildfire risks over time?

A. No, however, PacifiCorp expects to observe a small reduction in its pole intrusive reject rates over time as a result of these replacements.

Q. Please describe fireproof mesh wrapping for wooden poles and how it works.

A. The fireproof mesh wrapping is intumescent, meaning that it swells in the event of a fire. That swelling protects the underlying wood. The companies that manufacture the wrapping have tested the material at testing labs to demonstrate the material's effectiveness at protecting wooden poles from fire damage.

Q. Why not wrap all wooden poles with fireproof mesh?

A. Not every pole on PacifiCorp's system is expected to be at high risk of wildfire. Installing the mesh on all poles would increase costs without an expected corresponding benefit. PacifiCorp's Oregon system uses more than half a million poles, at approximately $100 per pole, the costs of such an effort would be over $50 million. Aside from the costs, it would take years for the Company to complete such an extensive program. Finally, there are maintenance trade-offs to encircling a pole with fireproof mesh, such as impeding intrusive testing, that weigh in favor of targeted use of fireproof mesh over a system-wide application.

Q. How will the Company determine where fireproof mesh wrapping wooden poles will have the biggest wildfire mitigation impact?

A. PacifiCorp will focus on FHCAs to determine which poles to fully replace and which to employ fireproof mesh. The poles that will be covered with the mesh are those that are relatively young, structurally sound, have no outstanding observed maintenance needs, and have limited joint use attachments affecting the strength of the pole.

Q. What criteria will the Company use to measure the success of its pole wrapping and pole replacement efforts?

A. When and if fires occur near facilities that have received the pole wrapping, PacifiCorp will be able to observe the success of its efforts. To monitor this, the Company will record locations where the fire mesh is installed, and areas where wooden poles are replaced with composite poles, to assess the relative performance of each during any wildfires that occur.

Advanced Protection and Control

Q. Please explain what advanced protection and control measures are in the context of wildfire mitigation.

A. Advanced protection involves the deployment of sophisticated protection control strategies, particularly advanced relay technologies on distribution and transmission lines. In the context of wildfire risk mitigation, these protection control strategies involve the device operations that take place when fault events occur. In contrast to the wildfire mitigation strategies discussed above, which relate to limiting the occurrence of fault events, advanced protection and control strategies relate to limiting the length and magnitude of a fault event. Specifically, the window of time after fault events represents the time when electrical system facilities pose the highest risk of igniting adjacent fuel, which could result in a wildfire. Reducing the time between when a fault occurs and that fault condition is cleared, reduces the risk of igniting adjacent fuel, and therefore also reduces wildfire risk.

Q. Please describe the differences between legacy electro-mechanical relays and modern microprocessor relays.

A. Unlike an electro-mechanical relay, microprocessor relays are able to exercise programmed functions nearly immediately (near the speed of light), which results in much faster device response during fault conditions. Microprocessor relays also allow for greater customization to address environmental conditions through multiple settings groups; they are also better able to incorporate complex logic to execute specific operations. Also, in contrast to electro-mechanical relays, microprocessor relays retain event logs that provide data for fault location and later analysis.

Q. Will these modern microprocessor relays provide the Company more data regarding line contacts and other faults on the system than the electro-mechanical relays currently used on PacifiCorp's system?

A. Yes. These new relays will capture a variety of event logs, including waveforms during fault events.

Q. How will the additional data provided by these new relays help the Company in its wildfire mitigation efforts?

A. In addition to faster fault clearing schemes, these relays improve response times since they can identify locations where disturbances emanate from, which will be used by field and office teams to assess these situations. PacifiCorp will also use this data during investigations of events to ensure that the devices performed consistent with the programmed settings and to evaluate other wildfire mitigation technologies.

Q. What were the Company's capital expenditures with respect to its advanced protection and control wildfire mitigation efforts in 2019?

A. As shown in Table 1, in 2019, PacifiCorp made capital expenditures of approximately $458,000 in its Oregon distribution system and $1,308,000 ($358,000 Oregon-allocated) in its transmission system to implement advanced protection and control wildfire mitigation measures.

Q. What capital expenditures will the Company make in 2020 and what does the Company forecast for 2021 and 2022 with respect to its advanced protection and control wildfire mitigation efforts?

A. As shown in Table 1, in 2020, PacifiCorp will make capital expenditures of approximately $2,330,000 in the Oregon distribution system and $4,743,000 ($1,234,000 Oregon-allocated) in the transmission system to further implement advanced protection and control measures, as its wildfire mitigation efforts accelerate. PacifiCorp anticipates that level of expenditure to continue into 2021, when approximately $2,465,000 will be spent on advanced protection and control in its Oregon distribution system, and $3,774,000 ($982,000 Oregon-allocated) in its transmission system. In 2022, the company anticipates a slightly lower expenditure of $1,700,000 in its Oregon distribution system and $750,000 ($195,000 Oregon-allocated) in its transmission system.

Condition Corrections

Q. Please describe the Company's condition correction process as it relates to wildfire mitigation efforts.

A. When the Company inspects its system infrastructure, it documents "conditions" which reflect observed characteristics, including wear or damage, of a given element of PacifiCorp's system. These conditions are reported in PacifiCorp's Facility Point Inspection (or FPI) system, and ranked for priority. Based on that priority, work is assigned to personnel to correct and repair conditions requiring attention.

Q. Has the Company modified its inspection process to address increased wildfire risks in FHCAs?

A. Yes. A subset of conditions observed during inspections pose a potential source of wildfire ignition. To better track these, PacifiCorp created a classification in FPI called "fire threat conditions." This designation allows the Company to assign personnel to accelerate correction of these conditions, and to address them in advance of high wildfire risk periods to help reduce the risk that fire threat conditions will lead to a wildfire.

Q. What were the Company's capital expenditures with respect to condition correction to mitigate wildfire risk in 2019?

A. As shown in Table 1, in 2019, PacifiCorp made capital expenditures of approximately $200,000 ($52,000 Oregon-allocated) on condition corrections in its transmission system as part of its wildfire mitigation efforts.

Q. What capital expenditures will the Company make in 2020 with respect to condition correction to mitigate wildfire risk?

A. As shown in Table 1, in 2020, PacifiCorp will make capital expenditures of approximately $100,000 ($26,000 Oregon-allocated) on condition corrections in its transmission system as part of its wildfire mitigation efforts. PacifiCorp does not anticipate expenditures in 2021 and 2022.

Q. How does the Company plan to measure the success of this modified inspection process?

A. As with many of these wildfire mitigation efforts, the best indication of effectiveness will be reduced incidents of wildfire ignitions over time. While comparisons between periods prior to implementing these efforts to the periods following may provide some useful information, those comparisons will not be immediately informative due to a lack of sufficient data.

Q. How will that information allow the Company to improve and refine its inspection process overtime to better address wildfire risks in FHCAs?

A. PacifiCorp will be able to better identify "conditions" that cause higher fault rates. By focusing on these "conditions" the Company will continue to improve and refine its inspection process in FHCAs.

Access Roads and Rights-of-Way

Q. Please explain how the addition of new access roads and other improvements, and increasing rights-of-way on transmission lines support the Company's wildfire mitigation efforts?

A. Increasing access roads help to reduce the likelihood of equipment loss when wildfires occur by increasing accessibility for firefighters. While increasing transmission line rights-of-way benefit firefighter access (and also creates potential fire breaks for fire defense positions), it also affords better access for utility response personnel and can be valuable in improving the utility corridor.

Q. What capital expenditures will the Company make in 2020 with respect to access roads and increased rights-of-way?

A. As shown in Table 1, in 2020, PacifiCorp will make capital expenditures of approximately $1,000,000 ($260,000 Oregon-allocated) to expand access roads and rights-of-way across its transmission system. PacifiCorp does not anticipate expenditures in 2021 or 2022.

Q. How does the Company plan to evaluate and improve upon its access roads and rights-of-way efforts over time?

A. PacifiCorp will continue to take feedback from firefighters and patrol personnel regarding access roads and rights-of-way to monitor its efforts over time.

Q. Please describe the benefits of PacifiCorp's wildfire mitigation investments.

A. Proactively investing in wildfire mitigation projects in identified FHCAs reduces the risk of catastrophic fire caused by PacifiCorp's facilities, directly benefiting PacifiCorp customers. In addition, reducing the risk of catastrophic fire benefits fire response agencies, preserves customer property and Company facilities, and minimizes the cost of rebuilding.

Q. How do PacifiCorp's wildfire mitigation efforts relate to the Company's standard safety and compliance activities?

A. Many of the wildfire mitigation strategies I discuss above go beyond standard utility practice. For example, PacifiCorp does not, in the normal course, install covered conductor or wrap poles in fireproof mesh. These measures are in direct response to changing best practices for mitigating wildfire and are incremental to work PacifiCorp would do in the ordinary course of its business. Similarly, activities such as replacement of existing equipment (replacing distribution poles with composite material poles, replacing electro mechanical relays, etc.) are now informed by the potential for the replacement to mitigate wildfire risk, location of the existing equipment within FHCA, and may involve accelerated replacements. Certain activities such as conditions corrections, are a standard part of PacifiCorp's safety operations. Prioritizing and accelerating conditions corrections that are identified as potentially increasing wildfire risk, however, is a new feature of PacifiCorp's conditions corrections protocols.

Wildfire Mitigation Program Costs for 2021 - 2022

Q. Will the Company's wildfire mitigation projects continue after 2020?

A. Yes. As discussed in docket UM 2013, PacifiCorp's Application for Deferred Accounting Related to Wildfire Risk Mitigation Measures, PacifiCorp's wildfire mitigation efforts will span multiple years.[2]

Q. Does PacifiCorp have a proposal for cost recovery of costs associated with wildfire mitigation projects in 2021 and 2022?

A. Yes. As described in the testimony of Ms. Etta Lockey, the Company is proposing a Wildfire Cost Recovery Mechanism to recover the costs of continued wildfire mitigation activities in 2021 and 2022.

IV. DELTA FIRE DAMAGED FACILITIES REBUILD

Q. Please provide an overview of the Delta fire and how it impacted PacifiCorp facilities.

A. The Delta fire ignited on September 5, 2018, two miles north of Lakehead in Shasta County, California. The fire rapidly grew in size and burned along the Interstate 5 corridor near Slate Creek and Dog Creek. The fire burned for weeks and consumed approximately 60,000 acres. The PacifiCorp facilities damaged by the Delta fire included a six-mile section of the 115 kilovolts (kV) transmission line (Line 14) and a five-mile section of the 69 kV transmission line (Line 2). Both sections required a

[2] *See In the matter of PacifiCorp dba Pacific Power's Application for Deferred Accounting Related to Wildfire Risk Mitigation Measures*, Docket No. UM 2013, Application for Deferred Accounting (May 14, 2019).

complete rebuild. Please refer to Exhibit PAC/1102 for a map of the Delta Fire transmission rebuild.

Q. Please describe the investment for the rebuild of the facilities damaged by the Delta fire.

A. The rebuild project consisted of replacing 78 transmission structures on Line 14 and 110 transmission structures on Line 2 that were impacted by the Delta fire. Also included in this project were associated vegetation management (clearing the rights-of-way of hazard trees), access road repairs, environmental and archaeological studies, inspections and surveys, material hauling charges, and other project oversight requirements. The total-company cost for the rebuild project was approximately $36.1 million, or $9.4 million on an Oregon-allocated basis.

Q. Please describe the benefits of rebuilding the transmission lines damaged by the Delta fire.

A. The Delta fire damaged both Line 14 and Line 2 to the point where both lines were inoperable and not available as part of the integrated PacifiCorp transmission system. While there are alternative sources and paths available while transmission lines are out, this reduces the overall capability and flexibility of the transmission system as a whole. For example, Line 14 is an interconnection with Pacific Gas and Electric Company from the south that is normally open, but serves as an alternate source if PacifiCorp loses the source from Weed Junction. Leaving Line 14 out of service for any duration leaves the system on a radial feed from the north and increases reliability risk to PacifiCorp customers. For these reasons, rebuilding the sections of Line 14 and Line 2 that were damaged provides benefits to PacifiCorp's Oregon customers.

V. PORTLAND UNDERGOUND NETWORK MONITORING

Q. Please briefly describe the Portland underground network.

A. The LVSN is a network of equipment and technologies that provides enhanced reliability to specific sections of PacifiCorp's Portland service territory. It is designed to ensure reliable provision of electric service to customers and businesses with high-reliability needs. The LVSN is a complex system due to the mesh configuration. A mesh network configuration provides maximum reliability and is used by utilities in congested areas, such as metropolitan and suburban business districts. The system is composed of many aging components, including switches, transformers, cable, and network protectors, and visibility into the network's operational status is limited to manual inspections of equipment in vaults and man-holes. The lack of visibility and situational awareness associated with the LVSN exposes the Company and customers to major outages if equipment or the system fails or does not operate correctly. If those issues go unnoticed, the result can cascade into large outage events with long recovery timelines.

Q. How is PacifiCorp responding to this potential risk?

A. PacifiCorp is responding to this potential risk through the installation of the VaultGard network monitoring system for the LVSN that covers approximately 70 blocks in the downtown Portland area, with additional vaults extending towards the Albina Substation.

Q. What are the specific benefits of the VaultGard system?

A. The installation of the VaultGard network monitoring system for the LVSN provides status information to facilitate control of field devices remotely allowing for notifications and alarms to be sent to a central control center to alert operators of equipment abnormality. These monitoring capabilities allow the Company to identify potential system conditions/deficiencies before major outages occur.

Q. Please describe the components included in the network monitoring system.

A. The scope of the project includes 73 VaultGard systems for the downtown Portland network, and eight VaultGard systems for the Lloyd network. The project also includes installation of a fiber communications system and connection of all network protectors across all vaults in the downtown and Lloyd networks.

Q. Please describe the costs associated with this project.

A. The current costs are $7.2 million. This includes the network monitors put in service in 2019. The projected additional costs through the end of the project are $496,000, with approximately $130,000 carrying over into 2020. This remaining spending is related to the delay of the VaultGard commissioning in a few locations described below.

Q. What is the status of this project?

A. All VaultGard assemblies are installed and commissioned with the exception of a few locations. The VaultGard assemblies for two locations are installed, but not yet commissioned because they are direct metered and PacifiCorp does not yet have an agreement in place with the building owners. The VaultGard commissioning in a third location is delayed due to recent remodeling activities at the location limiting access to one of PacifiCorp's vault. PacifiCorp and the owners of the building have an agreement in place that allows PacifiCorp unencumbered access to its vaults.

PacifiCorp is currently in negotiations with the tenant at the impacted location to resolve the access issue.

Q. How is the inclusion of the LVSN in rates beneficial to customers and otherwise in the public interest?

A. As a result of the LVSN, PacifiCorp will be able to improve customer service levels and introduce a greater level of system monitoring to avoid end-user equipment damage and identify potential system conditions so they may be addressed before outages occur on the LVSN. In addition, the implementation the VaultGard monitoring system creates a platform allowing PacifiCorp increased visibility and control of the electrical network resulting in improved response times to system conditions.

VI. OREGON AMI PROJECT

Q. Please briefly describe the Oregon AMI Project.

A. The Oregon AMI Project began in 2017 and was completed in early 2020. The Project consisted of the on-site replacement of approximately 627,000 existing customer meters with AMI meters and installation of AMI-related technology and telecommunications infrastructure, including construction of a field area network across the 21,292 square miles of PacifiCorp's Oregon service territory.

The Oregon AMI Project leveraged existing information technology infrastructure, which was developed in connection with PacifiCorp's California AMI project. This infrastructure was modified and expanded to support Oregon-specific functionality. With implementation of the Oregon AMI project complete, customer usage data is now sent wirelessly to PacifiCorp's meter data management system and is available to customers via the Company's website. In addition, PacifiCorp is able to remotely connect and disconnect electric service.

Q. Please describe the specific components of the AMI system that PacifiCorp invested in as part of the Oregon AMI Project.

A. The Oregon AMI Project consists of the following four primary components and work streams:

1. Installation of AMI

AMI contains a network interface card that enables two-way communication to and from the Company. It is also capable of capturing analytic data, such as temperature, voltage, and power quality. AMI captures meter readings at pre-set intervals and transmits read data wirelessly to the Company. Residential and small commercial meters contain a disconnect switch that enables remote connect and disconnect functionality.

2. Installation of Field Area Network

A field area network consists of communication devices, referred to as access points and relays, which communicate wirelessly to and from a number of meters in a given geographic area. Using the relays, data is transmitted from the access points to the utility's information technology infrastructure, often referred to as the "head-end," via cellular service. To create a field area network, the Company installed access points and relays on PacifiCorp's utility poles throughout its service territory.

3. Development, Installation, and Configuration of Head-End; Software Integration

The head-end is the Company's information technology infrastructure to which data is transmitted via the field area network. The head-end enables the Company to use the data captured by the AMI meter, which includes interval meter reads and temperature, voltage, outage, and power quality data. Such data is used by the Company via third-party AMI software that is integrated with the Company's legacy computer systems and the head-end, and enables the utility to send commands, such as connect or disconnect to the meter.

4. Development of Energy Usage Website

PacifiCorp has enhanced its existing energy usage website to include customer access to historic, hourly consumption based on data captured by the Company's AMI. This access provides customers with hourly energy consumption data from the previous calendar day. Another enhancement to the energy usage website is a bill projection for the current billing cycle. After seven days of usage in a billing month, a customer is able to log into their secure on-line account and see a projected bill amount for that particular billing month. PacifiCorp has also incorporated existing customer communication preferences with the bill projection data. Customers with AMI are able to set up a preference to receive an alert from PacifiCorp when the customer's projected bill will exceed a pre-determined dollar threshold designated by the customer. The customer may choose to receive the alert via text or email.

Benefits of AMI Deployment

Q. Why did PacifiCorp deploy AMI in Oregon?

A. PacifiCorp deployed AMI to provide customer benefits ranging from lowering operating costs (i.e., by reducing manual metering reading operations) and improving reliability, to providing customers with information and tools to better understand and derive greater value from their energy service. PacifiCorp identified AMI as a key technology to enable the Company to achieve long-term customer service objectives. Specifically, AMI functionality allows the Company to:

- Provide customers access to data regarding their hourly energy consumption, which will enable them to make more informed energy decisions;
- Reduce the number of estimated bills by providing the Company with actual meter data regardless of physical access barriers, bad weather delays, or other factors that can impede physical meter reading and give rise to estimated billing;
- Perform remote connect and disconnect which will enable service to be turned on and off on a near real-time basis without deploying employees to customers' premises;
- Detect and trouble-shoot power outage situations and react to customer outages in a more timely manner, without waiting for an outage notification from the customer;
- Obtain analytic information, such as temperature, voltage, and power quality data which can be used to assess system performance and improve service to customers;
- Provide better customer service by giving PacifiCorp's customer service representatives information necessary to provide accurate responses to customer inquiries and facilitate customer complaint resolution;
- Introduce efficiencies related to automation that reduce the cost to obtain meter reads and perform service connects and disconnects; and
- Minimize carbon dioxide emissions through reduced use of vehicles for meter reading operations.

Financial Analysis of Oregon AMI Project

Q. Please describe the costs associated with the Oregon AMI Project.

A. The total project cost of the Oregon AMI Project is $112.1 million in capital costs and $2.5 million in operation and maintenance (O&M) costs. Capital costs are broken down into the following components in support of the Oregon AMI Project: meters ($79.4 million), information technology and telecommunications ($25.5 million), and customer service and project management ($7.2 million). O&M costs are brokedown as follows: information technology and telecommunications ($0.5 million) and customer service and project management ($2.0 million). Going forward, new O&M costs will be incurred in order to run and support the AMI system, with annual operating costs estimated at $2.5 million following the first full year of implementation (year 2019). These costs include new call handling costs, field network hardware maintenance, and information technology maintenance and support.

Q. Please describe the potential O&M savings associated with the Oregon AMI Project.

A. The installation of AMI meters in Oregon will reduce costs related to manually reading meters. Subject to continued costs relative to opt-out customers, use of AMI meters also eliminates the need for employees to drive to customer locations to perform manual connect functions after normal business hours, reducing the amount of overtime required. Further, except with respect to manual meter reading services that will continue to be provided to opt-out customers, PacifiCorp will eliminate use of handheld devices and the cost of maintenance fees required to support those devices.

Q. Is PacifiCorp's investment in Oregon AMI Project prudent and cost effective?

A. Yes. PacifiCorp's investment in Oregon AMI Project is prudent and cost effective because of the advantages it affords PacifiCorp's customers. It may also result in reductions to PacifiCorp's annual operating costs as discussed above.

Q. Is the inclusion of the Oregon AMI Project in rates beneficial to customers and otherwise in the public interest?

A. Yes. As a result of the Oregon AMI Project, PacifiCorp will be able to improve customer service levels and introduce a greater level of transparency into the costs associated with energy usage decisions. In addition, the implementation of AMI creates a platform for smart grid modernization allowing PacifiCorp increased visibility into the electrical network and customer interface to assist in future programs and investments. The Oregon AMI Project also results in incidental benefits to the public generally, including the reduction of vehicle emissions due to the decrease in manual meter readings.

VII. CONCLUSION

Q. Please summarize your testimony.

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. My testimony outlines the methodology that PacifiCorp has used to identify locations and specific projects to help mitigate the risk of catastrophic wildfires in the FHCA. I also explain the need to rebuild critical facilities that have been damaged by wildfires.

My testimony also demonstrates the Company's commitment to improve customer service levels through the introduction of technology that allows PacifiCorp increased visibility into the electrical network and customer interface in order to provide increased reliability and response to outages and equipment issues.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/1101
Witness: David M. Lucas

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of David M. Lucas

PacifiCorp Service Territory with FHCA and Wildfire Perimeters

February 2020

RISK-BASED APPROACH: Fire High Consequence Areas (FHCA)

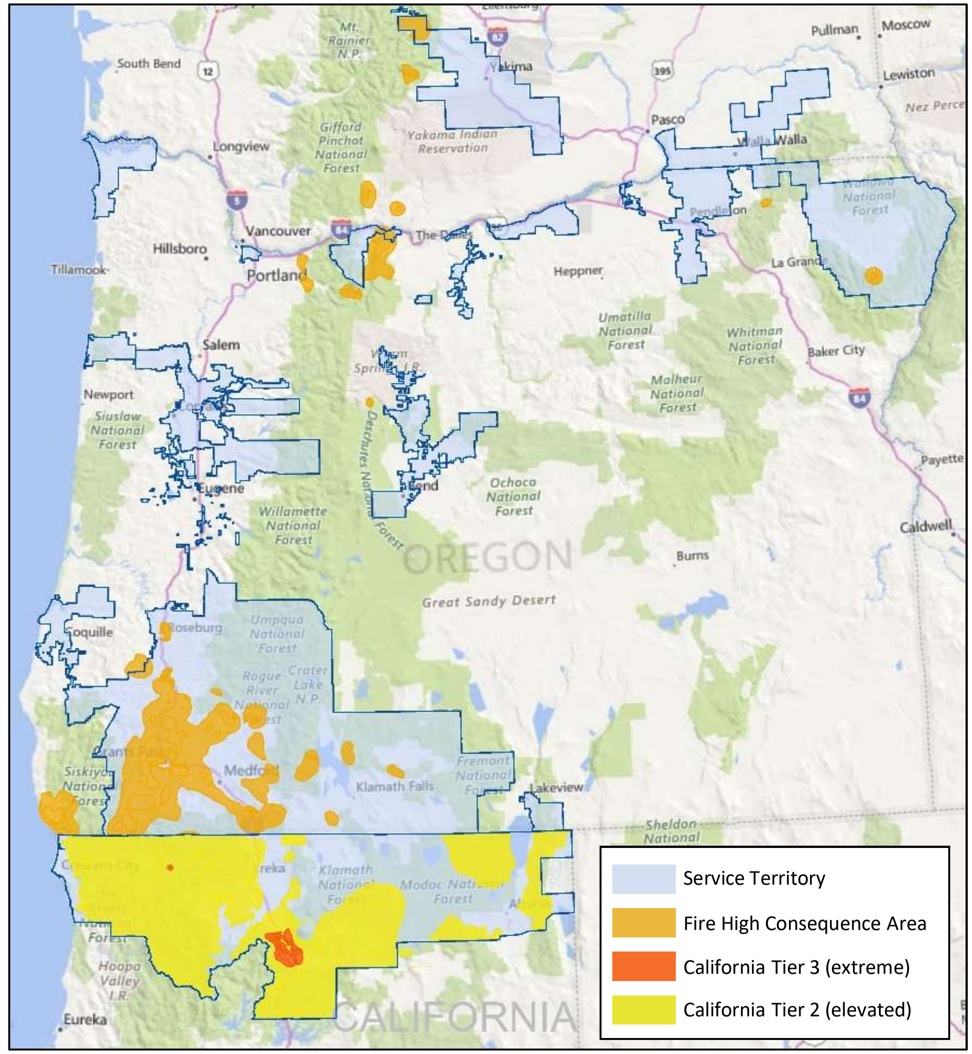
- Utilizing the same modeling concepts used in California, areas were identified in Oregon and Washington where there is an elevated risk of utility-associated wildfires to ***occur*** and ***spread rapidly***, and where communities face an elevated risk of damage or harm from wildfires

- 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

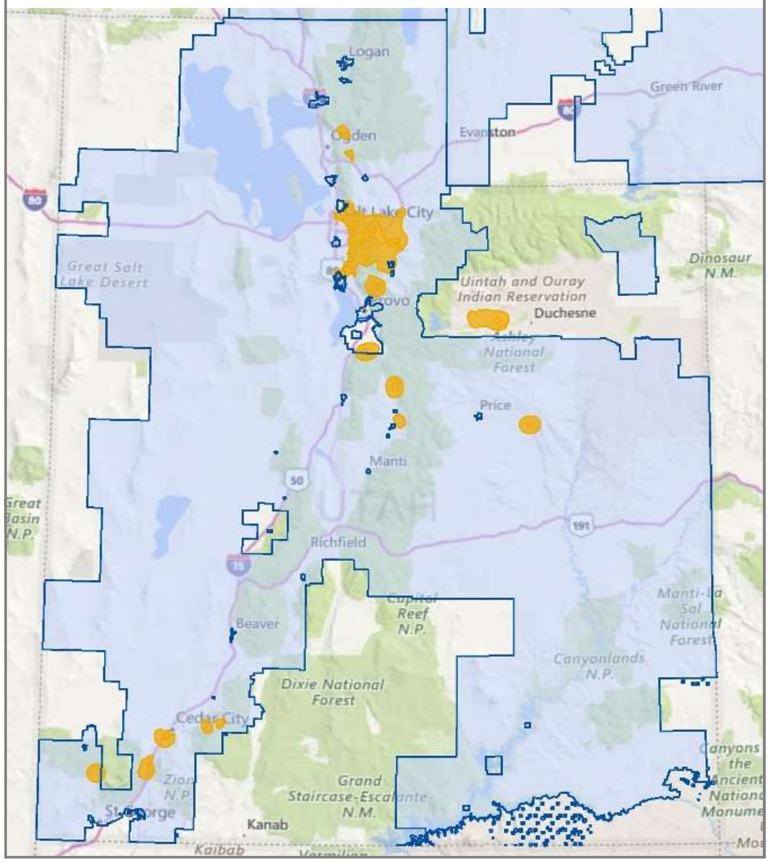
- FHCAs are used to prioritize wildfire mitigation initiatives, such as, increased inspections, system hardening and proactive de-energization

Washington, Oregon, California Service Territory

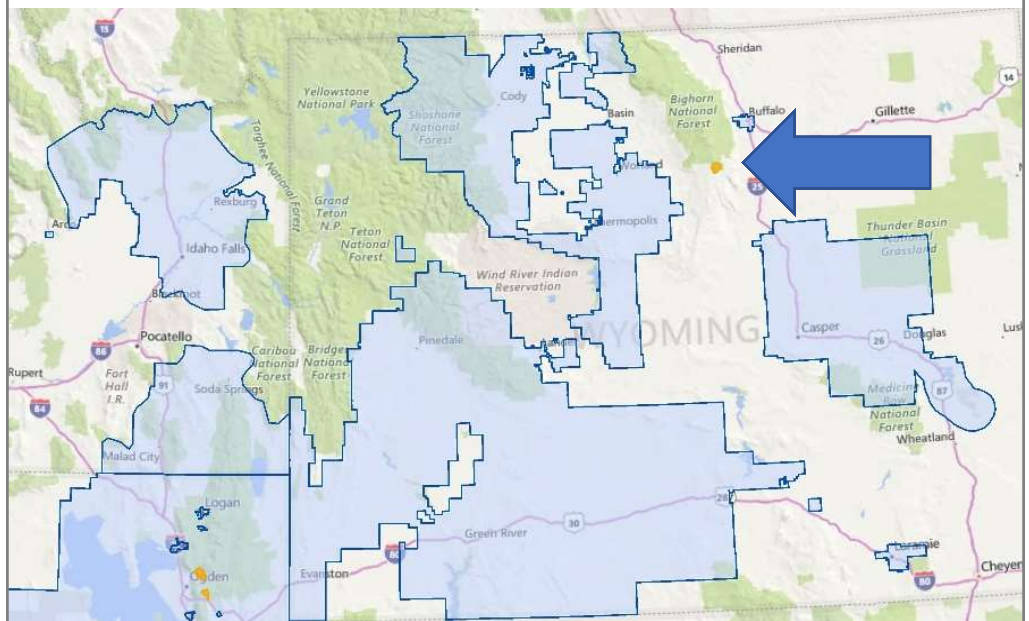


RISK-BASED APPROACH: Fire High Consequence Areas (FHCA)

Utah Service Territory



Wyoming / Idaho Service Territory



Service Territory	
Fire High Consequence Area	

Docket No. UE 374
Exhibit PAC/1102
Witness: David M. Lucas

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of David M. Lucas

Delta Fire Damaged Transmission Rebuild

February 2020

Delta Fire Transmission Rebuild Diagram

Docket No. UE 374
Exhibit PAC/1200
Witness: Melissa S. Nottingham

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Melissa S. Nottingham

February 2020

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ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp.

A. My name is Melissa S. Nottingham and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Manager, Customer Advocacy and Tariff Policy. I am testifying for PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

Q. Please describe your education and professional experience.

A. I have a Bachelor of Arts in English from Arizona State University and continue to pursue continuing education courses relevant to the utility industry. I began working for PacifiCorp in 1996, and worked in various positions with progressive responsibility for the past 20 years. For the past 10 years, I have been the Manager of Customer Advocacy and Tariff Policy in the Company's Regulation department.

Q. Please describe your current duties.

A. My current duties include overseeing a team of five regulatory analysts who respond to consumer commission complaints, sponsoring tariff changes, ensuring compliance with the Company's tariff rules, and participating in general rate cases and other regulatory proceedings for PacifiCorp's six state service territories. In addition, I oversee a team of three business analysts responsible for the administration of the contracts for new electrical load and the implementation and operation of the Company's customer guarantee program. As my team supports the Company's tariff rules in each state, we also support changes to Schedule 300, which are the charges associated with the implementation of the rules.

Q. Have you appeared as a witness in other regulatory proceedings?

A. Yes. I have testified in proceedings before the California Public Utilities Commission and the Washington Utilities and Transportation Commission.

II. PURPOSE OF TESTIMONY

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

A. My testimony supports proposed changes to Schedule 300 of the Company's Oregon tariff schedules, Rule 10, Rule 11D, and a proposal for customers to receive a credit for paperless billing.

The proposed changes to Rule 10, Rule 11D, and Schedule 300, Charges as Defined by the Rules and Regulations, are provided in Mr. Robert M. Meredith's Exhibit PAC/1401.

Finally, I propose housekeeping changes to Schedule 300 regarding the referenced rules.

Q. Why are you proposing these changes?

A. The proposed changes reflect the Company's continued commitment to lower costs for our customers, and to empower customers to control their monthly bills.

Q. Please provide a summary of your testimony and the proposed changes.

A. My testimony proposes an update to several customer charges in Schedule 300. The Company reviewed the costs associated with Schedule 300 charges and identified areas where costs have changed. A variety of factors, including automation of returned checks and fluctuations in financial models for determining Facilities Charges, have contributed to lower costs and different values. Accordingly, the

Company is proposing to sync customer charges to more accurately reflect current costs.

My testimony proposes to update the applicability of the Service Connection Charge to certain applicants requesting service connection at a location with remote connection capability to reflect the Company's ability to now perform remote connections and avoid sending an employee to the premises to connect.

My testimony also proposes to implement a bill credit for customers who choose paperless billing (Paperless Bill Credit). The proposed Paperless Bill Credit will send a price signal to customers to incentivize behavior that results in actual cost savings for the Company. The Paperless Bill Credit will provide a monthly benefit to customers who participate as well as create an incentive for customers to adopt more sustainable practices.

All of the proposed changes are a continuation of PacifiCorp's ongoing commitment to provide fair and reasonable charges by closely managing expenses while still meeting customers' increasing expectations.

III. SCHEDULE 300 – CHARGES AS DEFINED BY THE RULES AND REGULATIONS

Q. Please describe the changes PacifiCorp is proposing to the Schedule 300 charges.

A. Table 1 shows the rule, a description of the charge, the current charge, and the proposed charge.

TABLE 1

Rule	Description of Charge	Current	Proposed
R. 10-2	Returned Payment Charge	$20	$12
R. 13-2	Facilities Charges, at Less than 57,000 volts, installed at Consumer's Expense	0.5% per month	0.4% per month
R. 13-2	Facilities Charges, at Less than 57,000 volts, installed at Company's Expense	1.4% per month	1.2% per month
R. 13-2	Facilities Charges, at and above 57,000 volts, installed at Consumer's Expense	0.3% per month	0.2% per month
R. 13-2	Facilities Charges, at and above 57,000 volts, installed at Company's Expense	0.9% per month	0.85% per month
R. 13-9[1]	Temp Service Charge – Single Phase	$85	$164
R. 13-9	Temp Service Charge – Three Phase[2]	$115	$164

Returned Payment Charge

Q. Please describe the Returned Payment Charge.

A. If a customer presents a payment that is returned by the customer's bank, the Company incurs a cost to process the returned payment. Payments can be returned for a variety of reasons, including, but not limited to, insufficient funds, incorrect account numbers, or closed accounts.

Q. What is the current Returned Payment Charge?

A. The current Returned Payment Charge is $20.

Q. What is the proposed change to the Returned Payment Charge?

A. PacifiCorp proposes to reduce the Returned Payment Charge from $20 to $12.

[1] PacifiCorp Rate Schedule 300 currently notes the Temporary Service Charge comes from R. 13-9. The reference should read R. 13-11 and is corrected in housekeeping changes later in the testimony.
[2] PacifiCorp is proposing to consolidate the single phase and three phase into one Temporary Service Charge, with the same charge amount.

Q. Why is PacifiCorp proposing this change?

A. Banks are now able to electronically transfer money from one bank to another bank with less human interaction. This automation of a portion of the return payment process has led to reduced costs to the Company when a payment is returned. Each time the Company's bank receives a returned item, the bank assesses a fee to the Company. These fees account for the majority of the cost to the Company when a customer's payment is not acknowledged as valid. The fee can vary from $11 to $16 based on the bank presenting the returned payment, the amount of the payment, and the number of times the payment is presented for payment.

While processing these payments has become more automated, labor costs are not completely eliminated. Each returned item requires a PacifiCorp employee to update the account information and reverse the payment if the billing system has already posted the payment to the account. The labor costs range from $1 to $6 per transaction. The Company is proposing $12 as it closely represents the low-end of the average costs of both the labor and the bank fees associated with these returned payments. See Exhibit PAC/1201 for the calculation of the proposed charge.

Facilities Charges

Q. What changes are you proposing for Facilities Charges?

A. PacifiCorp is proposing to lower the Facilities Charges for new distribution and transmission service. Table 2 includes both the current Oregon Facilities Charge and proposed Facilities Charge by voltage.

TABLE 2

Oregon Facilities Charge		
	OR Current	**OR Proposed**
Distribution-Voltage Equipment (<57,000 volts)		
On Customer $	0.5%	**0.4%**
On Company $	1.4%	**1.2%**
Transmission-Voltage Equipment (≥57,000 volts)		
On Customer $	0.3%	**0.2%**
On Company $	0.9%	**.85%**

Facilities Charges are calculated using the financial models provided as Exhibit PAC/1202.

Q. What are Facilities Charges?

A. Facilities Charges are the fixed costs of ownership of facilities necessary to connect new load to PacifiCorp's system, including but not limited to, the return and recovery of any capital investment, operations and maintenance costs, and ongoing taxes. Since these costs vary based on the type of service installed and are funded by both PacifiCorp and the customer, there are four different Facilities Charges percentages, as reflected in Table 2. The percentages in Table 2 are applied to both the customer's up-front payment for new service and PacifiCorp's capital investment. The product of these calculations is the Facilities Charges.

Q. Why is the Company proposing to lower the Facilities Charges?

A. Over time, PacifiCorp has reduced costs and increased operational efficiencies, reducing the minimum amount required to own and operate the required facilities. By lowering the percentages used to calculate the Facilities Charges, the savings will be passed onto the customer. PacifiCorp is passing these savings on to customers through the proposal to lower the Facilities Charges. Please see Exhibit PAC/1202 for more detail.

Q. Please describe when Facilities Charges are billed to a customer.

A. When a customer requests to connect new or additional electric load on the Company's system, the request can trigger both capital investments and additional maintenance costs. To ensure the new revenue generated will cover the costs associated with the new electric load request, the Company contracts with the new customers to recover the costs with a Contract Minimum Billing.

The Contract Minimum Billing is the greater of two items: the customer's bill or 80 percent of the customer's bill plus the Facilities Charge. If the revenue from the electrical usage covers the additional costs to own and operate the facilities, the Contract Minimum Billing is fulfilled or the costs to own and operate are recovered through the energy usage. If the revenue does not cover the additional costs to own and operate the new electrical load, the Facilities Charge is added to the billing.

Temporary Service Charge

Q. Please describe the Temporary Service Charge.

A. A Temporary Service Charge applies when a customer requests the energization of a temporary pedestal for temporary electric service. Temporary pedestals are typically needed for periods when a premise is under construction. The Temporary Service Charge covers the labor cost to bring either a single-phase or three-phase service line to the temporary pedestal and energize the service. Once the service is energized, the requesting customer is billed for the energy used. After the structure is completed, the temporary service is de-energized and the meter is relocated to the permanent meter base.

Q. What is the current Temporary Service Charge?

A. The current charge is $85 for single-phase service and $115 for three-phase service.

Q. What are the proposed changes to the Temporary Service Charge?

A. PacifiCorp is proposing to increase the charge to $164 for all temporary service installations and combine all phases into one charge. The $164 charge is based on the current loaded rate for one hour of journeyman time, which is similar to the methodology used when the Temporary Service Charge was initially calculated in 1987.

Q. Why is PacifiCorp proposing a change to the Temporary Service Charge?

A. The Temporary Service Charge has not been updated since 1987 and does not reflect the Company's current cost to provide this service. See Exhibit PAC/1201 for a summary of the cost calculation.

Paperless Bill Credit

Q. Please describe the Paperless Bill Credit.

A. PacifiCorp is proposing to add a credit to Schedule 300 and Rule 10 to provide customers a monthly credit if they have enrolled in paperless billing.

Q. What is the proposed amount of the Paperless Bill Credit?

A. The proposed monthly credit is $0.50.

Q. Why is PacifiCorp proposing a monthly credit for paperless billing?

A. PacifiCorp is proposing a Paperless Bill Credit that is correlated to the savings and benefits of not sending a paper bill to a customer when that customer voluntarily enrolls in paperless billing. Electronic delivery of the customer's monthly bill eliminates the cost of the bill paper, the envelope, printing and stuffing of the envelope, and the postage to mail the bill. Eliminating these costs results in savings of approximately $0.49 per metered service. By passing this savings to the customer in a $0.50 monthly credit, the Company is encouraging customers to utilize a lower cost billing option and a more environmentally friendly option. All customers, whether they are currently participating in or are new to paperless billing, are eligible to receive a credit as long as they are enrolled in paperless billing. Please see Exhibit PAC/1203 for more detail on the calculation of the credit and Mr. Meredith's Exhibit PAC/1401 for the proposed tariff changes to Schedule 300 and Rule 10.

Work Performed at Consumer's Request–Service Connection Charge

Q. Please describe the changes PacifiCorp is proposing to Schedule 300 and Rule 11D?

A. PacifiCorp proposes to add language to Rule 11D to indicate there is no Service Connection Charge for customers requesting new service at a location with remote connection capability during after-hours or on weekends/holidays. For locations with remote connection capability, PacifiCorp will no longer be required to send an employee to the site to manually turn the power on for a new service connection. However, since not all meters in Oregon have been upgraded with a remote connection meter, the Company still anticipates employees traveling to and from non-remote connection meter locations to turn on electric service. Customers requesting service connection at locations without a remote connection capable meter will continue to be charged the Service Connection Charge.

In addition to the change to Rule 11D, PacifiCorp proposes to change the description of the Service Connection Charge in Schedule 300 to specify there is a charge for non-remote service connections after hours and on weekends, and no charge for remote service connection. Please refer to Mr. Meredith's Exhibit PAC/1401 for the proposed tariff change.

IV. HOUSEKEEPING

Q. What housekeeping changes are you proposing?

A. I am proposing housekeeping changes to Sheet No. 300.3 in Schedule 300 to correct inaccurate sheet references. The Temporary Service Charge is changed from Sheet R13-9 to R13-11 and the Contract Administration Credit is changed from Sheet R13-11 to R13-13. Please see Mr. Meredith's Exhibit PAC/1401.

V. CONCLUSION

Q. Please summarize your testimony.

A. The proposed changes to PacifiCorp's Schedule 300, Charges as Defined by the Rules and Regulations, represent both the ongoing commitment by PacifiCorp to keep operational costs low for customers and align customer charges with cost. With one exception, all of the proposed charges are lower than current charges, and will benefit a comprehensive and diverse group of customers. The proposed change to Rule 11D will allow applicants connecting at a location with remote connection capability to connect after hours, weekends, and holidays while avoiding connection fees. The proposed bill Paperless Bill Credit creates an opportunity for customers to manage costs and directly receive the benefits of their choices.

Q. What is your recommendation regarding changes to Schedule 300, Rule 10, Rule 11D, and the proposed paperless bill credit?

A. I recommend that the Commission approve the changes to Schedule 300, Rule 10, Rule 11D, and the proposed Paperless Bill Credit (included in Rule 10).

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/1201
Witness: Melissa S. Nottingham

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Melissa S. Nottingham

Schedule 300 Charge Review

February 2020

Schedule 300 Fee Summary

Rule	Charge	Times Charged 7/1/18-6/30/19	Current Charge	Actual Cost	Proposed Charge	Comments
R.10-2	Returned Payment Charge	14,364	$20.00	$11.25 to $16.25	**$12**	The fees charged by the company's banks when a payment is returned and the labor to process returned payments on customer accounts. The fees vary based on the bank and how many times the same payment is processed.
R.13-2	Facilities Charges On Facilities at Less than 69,000 Volts Installed at Customer's Expense	Data Not Obtained	0.5% per month	N/A	**0.4 % per month**	Current data supports a reduction. The data is from the corporate Use of Facilities Charges found online in the corporate Financial Analysis Tools/Models. The facilities charges are based on the information reported in the company's Federal Energy Regulatory Commission Form No. 1 (FERC form 1), and supporting working papers.
R.13-2	Facilities Charges On Facilities at Less than 69,000 Volts Installed at Company's Expense		1.4% per month		**1.2% per month**	
R.13-2	Facilities Charges For Facilities at and above 69,000 Volts Installed at Customer's Expense		0.3% per month		**0.2% per month**	
R.13-2	Facilities Charges For Facilities at and above 69,000 Volts Installed at Company's Expense		0.9% per month		**0.85% per month**	
R.13-11	Temp Service Charge - Single Phase	1,838	$85.00	$164.18	**$164**	Increase in labor costs, calculated at one hour of the loaded labor cost for the type of employee performing the work.
R.13-11	Temp Service Charge - Three Phase	11	$115.00	$164.18	**Remove**	Three-phase temporary service is rarely used by our customers as the type of service lends itself to permanent installations. Recommend removing this cost and merging the two temporary service charges into one.
NEW	Paperless Bill Credit	0	0		**$.50 Bill Credit**	Each month, customers participating in paperless billing will receive a credit directly correlated to the savings and benefits of this option.

Payment Support Response
Contact(s): Tony Worthington

Test Year: Historical twelve months ending June 2019

Charge	Current Charge in Effect	Number of times the Charge was assessed during the test period	Employee Classification doing the work	Average Time to Perform Work	Activity Rate	Cost	Cost*
Returned Payment Charge	$20.00	14,364	Bank Charge	N/A	$5 to $10	$5.00	$10.00
			CCO	0.0041667	$36.24	$0.15	$0.15
			Payment Support	0.08666667	$55.56	$4.82	$4.82
			Customer Care	0.03333333	$38.58	$1.29	$1.29
						$11.25	$16.25

*Bank fees vary depending on the bank and the submissions. Costs are a range.

T&D Operations Responses
Contact(s): Scott Liedtke

Test Year: Historical twelve months ending June 2019

Charge	Current Charge in Effect	Number of times charged during test period	Employee classification completing work	Activity Rate of Employee	Average time for employee performing the work (minutes)	Average Task Time (hours)	Average travel time for employee performing the work	Actual Cost
Temporary Service Charge Service Drop and Meter only - Single Phase	$85.00	1838	Journeyman Lineman	$164.18	60	1	N/A	$164.18
Temporary Service Charge Service Drop and Meter only - Three Phase	$115.00	11	Journeyman Lineman	$164.18	N/A	N/A	N/A	N/A

Tariff Responses
Contact(s): Rob Stewart

Test Year: Historical twelve months ending June 2019

Charge	Current Fee in Effect	Comments
Facilities Charges On Facilities at Less than 57,000 Volts Installed at Customer's Expense	0.5% per month	Current data supports a reduction. The data is from the corporate Use of Facilities Charges found online in the corporate Financial Analysis Tools/Models. The facilities charges are based on the information reported in the company's Federal Energy Regulatory Commission Form No. 1 (FERC form 1), and supporting working papers.
Facilities Charges On Facilities at Less than 57,000 Volts Installed at Company's Expense	1.4% per month (corrected)	Proposed new: 1.2% per month. Current data supports a reduction. See explanation above.
Facilities Charges For Facilities at and above 57,000 Volts Installed at Customer's Expense	0.3% per month (corrected)	Proposed new: 0.2% per month. Current data supports a reduction. See explanation above.
Facilities Charges For Facilities at and above 57,000 Volts Installed at Company's Expense	0.9% per month	Proposed new: 0.85% per month. Current data supports a reduction. See explanation above.

Docket No. UE 374
Exhibit PAC/1202
Witness: Melissa S. Nottingham

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Melissa S. Nottingham

Facilities Charge Calculation

February 2020

USE OF FACILITIES CHARGES, Annual, %			
		2018	
		Distribution	Transmission
Company Provides Initial Capital Investment (allowance)			
1	Return on Capital	4.42%	4.94%
2	Recovery of Capital	2.83%	1.87%
3	State & Federal Income Taxes	0.99%	1.09%
4	Local Property Taxes	0.73%	0.80%
5	Operation & Maintenance	2.91%	0.82%
6	Administrative & General	0.53%	0.53%
7	Other Taxes	0.46%	0.13%
8	Customer Accounts & Services	1.49%	N/A
9	TOTAL (lines 1-8)	14.36%	10.18%
10	*Monthly %*	1.20%	0.85%
11	Monthly Proposed (rounded)	**1.20%**	**0.85%**
	Customer Provides Initial Capital Investment (customer advance)		
12	Subtotal Lines 4-8	6.12%	2.28%
13	Capital Replacement Annuity	0.91%	0.54%
14	TOTAL (lines 12-13)	7.03%	2.82%
15	*Monthly %*	0.59%	0.24%
16	TOTAL (lines 4, 5, 7 & 13)	5.01%	2.29%
17	*Monthly %*	0.42%	0.19%
18	Monthly Proposed (rounded)	**0.40%**	**0.20%**

Docket No. UE 374
Exhibit PAC/1203
Witness: Melissa S. Nottingham

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Melissa S. Nottingham

Paperless Bill Credit Calculation

February 2020

Proposed Paperless Credit Calculation

Average Cost of One Sheet Paper Bill	
Paper	$0.0107
Envelope	$0.0382
Printing and Mailing	$0.0562
Postage	$0.3910
Total Cost	$0.4961
Proposed Paperless Credit	($0.50)

Docket No. UE 374
Exhibit PAC/1300
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Shelley E. McCoy

February 2020

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Confidential Exhibit PAC/1308—Other Plant Closure Costs Details Adjustment Support

Confidential Exhibit PAC/1309—Pro Forma Plant Additions Adjustment Support

Confidential Exhibit PAC/1310—Repowering Capital Additions Adjustment Support

Confidential Exhibit PAC/1311—Energy Vision 2020 Wind Project Capital Additions Adjustment Support

Exhibit PAC/1312—Generation Plant Removal Adjustment, Cholla Unit 4 Amortization Schedule

Exhibit PAC/1313—Federal Tax Act Adjustment, Tax Cuts & Jobs Act Deferral Balances Amortization Schedule

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 Shelley E. McCoy, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, OR 97232. I am currently employed as the Revenue Requirement Manager for PacifiCorp.

Q. Briefly describe your educational and professional background.

A. I earned my Bachelor of Science degree in Accounting from Portland State University. In addition to my formal education, I have attended several utility accounting, ratemaking, and leadership seminars and courses. I have been employed by PacifiCorp since November of 1996. My past responsibilities have included general and regulatory accounting, budgeting, forecasting, and reporting.

Q. What are your responsibilities as Revenue Requirement Manager?

A. My primary responsibilities include overseeing the calculation of PacifiCorp's revenue requirement and the preparation of various regulatory filings in Washington, Oregon, and California. I am also responsible for the calculation and reporting of PacifiCorp's regulated earnings and the application of the inter-jurisdictional cost allocation methodologies.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony in California and Washington.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. My direct testimony addresses the calculation of the Company's Oregon-allocated revenue requirement, excluding net power costs (NPC), and the revenue increase requested in the Company's filing. Specifically, I provide testimony on the following:

- The calculation of the $78.0 million revenue increase requested in this general rate case representing the increase over current rates required for the Company to recover its Oregon non-NPC revenue requirement of $1,045.7 million. The Company currently recovers its NPC through the Transition Adjustment Mechanism (TAM).
- The selection of the historical period of the 12 months ended June 2019 (Base Period) as the basis for the test period in this proceeding.
- The development of the forecast test year in this case, which is the 12 month period ending December 31, 2021 (Test Period).
- The treatment of forecasted capital additions included in the revenue requirement calculations, which have been limited to projects placed in service before January 1, 2021, the beginning of the Test Period.
- The presentation of the normalized results of operations for the Test Period demonstrating that under current rates the Company will earn an overall return on equity (ROE) in Oregon of 9.3 percent, which is below the Company's currently authorized ROE of 9.8 percent and the 10.2 percent requested by the Company and supported by Ms. Ann E. Bulkley in this proceeding.

Q. How have you organized your testimony?

A. I have divided my testimony into three sections. I discuss the development of the Company's revenue requirement, including the base and test periods, in Section III, Revenue Requirement. In Section IV, Inter-jurisdictional Allocations, I address the allocation methodology used in this filing. In Section V, Oregon Results of Operations, I provide a description of the Oregon Results of Operations, including a review of the information contained in Exhibit PAC/1302.

III. REVENUE REQUIREMENT

Q. What is the revenue requirement to achieve the requested ROE in this case?

A. At current rate levels, the Company will earn an overall ROE in Oregon of 9.3 percent during the Test Period. This return is less than the 9.8 percent ROE authorized in the Company's 2013 general rate case, docket UE 263 (2013 Rate Case).[1] The Company is proposing to change the authorized ROE in this case to 10.2 percent. A 10.2 percent ROE produces a non-NPC revenue requirement of $1,045.7 million based on the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol). Exhibit PAC/1301 provides a summary of the Company's Oregon-allocated results of operations for the Test Period. Exhibit PAC/1302 provides the supporting details and calculations and is discussed in greater detail later in my testimony.

[1] *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). The settling parties to the stipulation in the 2013 Rate Case agreed to an overall rate of return of 7.621 percent and a 9.8 percent ROE for Oregon regulatory purposes. The stipulation was approved by the Commission in Order No. 13-474 on December 18, 2013.

Q. Please explain how you have treated NPC in this filing.

A. As noted above, the Company recovers its NPC through the TAM, which was concurrently filed with this general rate case[2] on February 14, 2020, for calendar year 2021 NPC. To model the non-NPC revenue requirement for this case, the Company first computed an overall Test Period revenue requirement including the NPC as filed in the TAM and then removed the NPC components from the overall price change. This approach is required to compute certain non-NPC components of the Test Period revenue requirement that are impacted by NPC-related items, such as the embedded cost differential (ECD), and various revenue-sensitive items. Details supporting the overall revenue requirement and the breakout between the TAM and general rate case are provided in Exhibit PAC/1301. Page 1 of Exhibit PAC/1301 also shows the division of revenue requirement between the TAM and general rate case components, and the resulting general-rate-case-related price change requested in this case.

Base Period

Q. Why did the Company use July 2018 through June 2019 as the historical basis, or Base Period, for the Test Period?

A. The Company selected the 12-month period ended June 2019 as the historical basis for this case because it was the most recent total-company data available for inter-jurisdictional allocations to achieve a filing date of February 14, 2020. The Company audits and extracts total-company accounting information with the data components necessary for state allocations on a semi-annual basis for the 12-month period ending June and December each year. This semi-annual data extract and review procedure is

[2] *In re the matter of PacifiCorp d/b/a Pacific Power 2021 Transition Adjustment Mechanism,* Docket No. UE 375 Advice No. 20-001 Initial Filing (Feb. 14, 2020).

a key control measure to ensure the accuracy and reliability of the data, which serves as the basis for each of the Company's results of operations and general rate case filings.

Q. Why was a February 14, 2020, filing date for this general rate case necessary?

A. In Order 09-274, the Public Utility Commission of Oregon (Commission) adopted a stipulation establishing guidelines for future TAM filings, including the following provision:

> In all future filings after UE 207 in a year in which the Company files a general rate case, the TAM will be included in or processed concurrently with the general rate case filing. *In future filings after UE 207, the Company agrees that both filings will be made no later than March 1 to allow for a January 1 rate effective date*.[3]

PacifiCorp is filing multiple rate cases across its six-state retail service territory. To accommodate various filing requirements and to manage internal resources, PacifiCorp is filing this general rate case and the concurrent TAM approximately two weeks earlier than the March 1 requirement set forth in Order 09-274.

Q. When will calendar year 2019 total-company data become available on an inter-jurisdictional allocation basis?

A. Only once total-company data is audited does it become available to begin analysis on an inter-jurisdictional allocation basis. Because of the unique complexities the Company faces as a multi-jurisdictional utility, additional time is necessary once total-company financial data is finalized to ensure state-allocated data is accurate. Due to these complex steps, calendar year 2019 data will not be available for use as the basis of a forecast test period until the end of April 2020, more than two months

[3] *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).

after this general rate case is filed.

Test Period

Q. What Test Period did the Company use to determine revenue requirement in this case?

A. The forecast Test Period used by the Company in this proceeding is the 12 months ending December 31, 2021.

Q. Why did the Company choose the year ending December 31, 2021, as the Test Period?

A. The Test Period in this case was selected to best reflect the conditions during the time the new rates will be in effect. The requested rate effective date in this case is January 1, 2021, which matches the Test Period used by the Company in the calculation of the revenue requirement. The Test Period in this general rate case also matches the test period used in the development of the NPC filed in the concurrent TAM.

Q. Please explain how the Company developed the revenue requirement for the Test Period.

A. Revenue requirement preparation began with historical accounting information; in this case, the Company used the 12 months ended June 30, 2019. Each of the revenue requirement components in the Base Period was analyzed to determine if a normalizing ratemaking adjustment was warranted to reflect normal operating conditions. The historical information was then adjusted to recognize known, measurable, and anticipated events.

Q. What is the significance of beginning with historical information?

A. The Company begins with historical accounting information and makes discrete adjustments to arrive at the Test Period revenue requirement. Beginning with historical information provides a solid foundation that is readily available for audit by all who wish to participate in the case. Individual adjustments are also available for review, and regulators and intervenors may determine each adjustment's relevance and accuracy.

Q. Please summarize the process used to adjust the historical accounting information to reflect Test Period revenues and costs.

A. Revenues are adjusted by applying the current Commission-approved tariff rates to the Test Period load projection. NPC are developed using the Generation & Regulation Initiative Decision Tools (GRID) model. The results of the GRID run for the Test Period are embedded in the results for calculation purposes only; as previously mentioned, recovery of these costs is sought through the TAM filing. Historical operations and maintenance (O&M) expenses, excluding NPC, are split into labor and non-labor components. Non-labor costs are adjusted for inflation using inflation indices developed specifically for electric utilities provided by IHS Global Insight (Global Insight) and for other distinct changes required to reflect conditions expected during the Test Period. Historical labor costs are also adjusted for contractual increases through the end of the Test Period.

Q. Does the Company rely solely on its own projections of future cost increases?

A. No. For example, the adjustment made to account for inflation between the historical period and the Test Period relies on inflation indices published by Global Insight.

Updates to pension and benefits expenses are made in accordance with forecasts from actuarial reports, while labor expenses governed by union contracts are walked-forward to Test Period levels using contractual labor increase percentages.

Q. How has the Company addressed areas where cost increases are different than inflation?

A. The Company's business units were asked to identify areas where budgets were significantly different than historical amounts, adjusted for wage increases and inflation. When differences were identified, the business units were asked to provide support for changes in the number, or frequency, of activities. An example of this type of adjustment is the Incremental O&M adjustment (adjustment page 4.7). Adjustments of this nature are necessary because inflation indices account for cost increases on existing units of production, not changes in volume or processes.

Q. How has federal income tax expense been calculated in this case?

A. Federal income tax expense for ratemaking is calculated using the same methodology that the Company uses in preparing its filed income tax returns. On December 22, 2017, Congress passed and the President signed the Tax Cuts and Jobs Act (TCJA) setting a new corporate income tax rate of 21 percent where the previous rate was 35 percent. Accordingly the federal income tax rate has been updated in the Company's revenue requirement model to 21 percent. Additional impacts to the Company's revenue requirement associated with the TCJA are discussed later in my testimony.

Q. Are changes being proposed to depreciation rates in this case?

A. Yes. This filing includes updated depreciation rates as filed with the Commission in the Company's September 2018 Depreciation Study.[4] Please see the supplemental testimony of Mr. Steven R. McDougal, Mr. John J. Spanos and Mr. Chad A. Teply on the proposed depreciation rates, including the updated decommissioning study for coal-fired resources, and the depreciation study in docket UM 1968.

Q. Has the Company made any proposals on the treatment of the deferred balances from the closure of Deer Creek mine in the Test Period?

A. Yes. In Order 15-161 issued in docket UM 1712, the Commission authorized creation of a deferred account to track the Deer Creek Mine closure costs and costs due to Retiree Medical Obligation Settlement Loss to be addressed in the subsequent ratemaking proceedings.[5] The Company is proposing in the current rate case to include all costs and savings in the Deer Creek mine deferred account in rate base to be amortized over three years.

Q. How is the retirement of Cholla Unit 4 reflected in Test Period revenue requirement?

A. As discussed in the testimonies of Ms. Etta Lockey and Mr. Rick T. Link, Cholla Unit 4 will be retired by December 31, 2020. Accordingly, the Company has removed associated rate base, O&M and depreciation expense in the calculation of revenue requirement for this rate case filing. A proposal to recover the remaining balances

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[4] *In the matter of PacifiCorp dba Pacific Power Application for Authority to Implement Revised Depreciation Rates*, Docket No. UM 1968, (Sept. 13, 2018).
[5] In the matter of PacifiCorp dba Pacific Power Application for Approval of Deer Creek Mine Transaction, Docket No. UM 1712, Order No. 15-161 at 1-2, 6-7, 10, 13 (May 27, 2015) and Order No. 15-166 at 2-3 (June 1, 2015).

and estimated decommissioning costs under the Generation Plant Closure Adjustment are discussed below in my testimony.

Q. How has the Company treated forecast capital additions to electric plant in service in this filing?

A. The Company has included capital additions to plant in service through December 31, 2020, rather than through December 31, 2021, which is the end of the forecast Test Period and the rate effective period. This treatment is consistent with the Company's 2010[6], 2012[7], and 2013 Rate Cases.[8]

Q. What changes are reflected in this rate case for the Klamath Hydroelectric Facilities?

A. PacifiCorp is a signatory to the Klamath Hydroelectric Settlement Agreement (KHSA), which provides for the transfer of four main-stem Klamath Hydroelectric Project developments, currently licensed to PacifiCorp, to a third-party dam removal entity that will pursue their removal. Consistent with the KHSA, depreciation rates for the Klamath assets were previously approved by the Commission to provide for full depreciation of the Klamath assets by December 31, 2019, in anticipation of the target date for dam removal of 2020 established in the KHSA. The Federal Energy Regulatory Commission (FERC) is currently evaluating the proposal to transfer the license for certain Klamath developments to the Klamath River Renewal Corporation,

[6] *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).
[7] *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).
[8] *See* Order No. 13-474.

the dam removal entity under the KHSA. The timing of when FERC will transfer the license, and when PacifiCorp's operations would ultimately cease, remains uncertain.

As the current project licensee, PacifiCorp's obligations under the license and FERC regulations continue to require capital investments to support ongoing project operations, ensure compliance with dam safety and other regulatory requirements, and to make other capital expenditures necessary to fulfill obligations under the KHSA to mitigate impacts of ongoing project operations.

Because the timing of license transfer and the cessation of generation from the Klamath assets remains uncertain, PacifiCorp has selected a depreciation rate of 20 percent per year for ongoing capital additions to the Klamath assets. PacifiCorp will seek regulatory approval to update the depreciation rate in the next depreciation study or once FERC rules on the license transfer application and there is more clarity about when operation of the Klamath assets will cease.

IV. INTER-JURISDICTIONAL ALLOCATIONS

Q. What methodology did the Company use to calculate the Oregon-allocated revenue requirement in this case?

A. The Company's Oregon-allocated revenue requirement is calculated using the 2020 Protocol, which was approved by the Commission in docket UM 1050 on January 23, 2020.[9] This is the Company's first Oregon rate case filing using the 2020 Protocol. The transition from the 2017 PacifiCorp Inter-jurisdictional Allocation Protocol to the 2020 Protocol results in limited changes to the allocations of revenue requirement to Oregon. The only changes in this filing are the increase to the cap on

[9] *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).

the ECD calculation and the elimination of the 2017 Protocol equalization adjustment.

V. OREGON RESULTS OF OPERATIONS

Q. Please describe Exhibit PAC/1302.

A. Exhibit PAC/1302, which was prepared under my direction, is the Company's Oregon results of operations report (Report). As previously explained, the Base Period for the Report is the 12 months ended June 30, 2019, which has been normalized and used to calculate the revenue requirement for the Test Period, the 12 months ending December 31, 2021. The Report provides totals for revenue, expenses, depreciation, NPC, taxes, rate base, and loads in the Test Period. The Report presents operating results for the Test Period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit PAC/1302 is organized.

A. The Report is organized into sections marked with tabs as follows:

- Tab 1 Summary contains a summary of Oregon-allocated results according to the 2020 Protocol. Page 1.1 breaks out the non-NPC results and calculates the revenue increase the Company is requesting as part of this general rate case (column 5). Page 1.2 contains a summary of the general rate case request.
- Tab 2 Results of Operations details the Company's overall revenue requirement, showing unadjusted costs for the Base Period and fully normalized results of operations for the Test Period by FERC account and 2020 Protocol allocation factor.
- Tabs 3 through 8 provide supporting documentation for the normalizing adjustments required to reflect on-going costs of the Company.
- Tab 9 provides the derivation of the ECD included in this case.

- Tab 10 contains the calculation of the 2020 Protocol allocation factors. Factors in this case are based on the load forecast through December 2021 and pro forma account balances.
- Tabs B1 through B20 contain the historical data for the Base Period and are organized by major FERC function.

Tab 3 – Revenue Adjustments

Q. Please describe the information contained within Tab 3 Revenue Adjustments.

A. Tab 3 begins with the Revenue Adjustment Index which contains a brief overview of the assumptions used to project Test Period revenues and a list of each normalization adjustment included in this section of the exhibit. The numerical summary (page 3.0.2) identifies each adjustment made to actual revenues and each adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a description of the adjustment.

Q. Please describe the adjustments made to revenue in Tab 3.

A. **Pro Forma Revenue (page 3.1) –** This adjustment normalizes general business revenues by adjusting to the pro forma revenue level for the Test Period based on forecasted loads. Page 3.1.4 shows a breakout of the TAM and general rate case revenues.

Wheeling Revenue (page 3.2) – This adjustment reflects the level of wheeling revenue for the Test Period by adjusting the actual revenue for normalizing, annualizing, and pro forma changes.

Renewable Energy Certificate (REC) Revenues (page 3.3) – This adjustment removes all REC revenue and REC deferrals booked during the 12 months ended June 2019. Most of Oregon's share of RECs is banked for compliance; however, not all RECs meet the Oregon Renewable Portfolio Standard (RPS) qualifications. Oregon's revenue from RPS ineligible RECs that are sold are passed backed to customers through the Oregon property sales balancing account per Commission Order 10-210 in docket UP 260.[10]

Ancillary Revenue (page 3.4) – This pro forma adjustment reflects ancillary revenue changes that are consistent with the forecast NPC treatment reflected in adjustment 5.1 discussed below. The ancillary revenue booked in the 12 months ended June 2019 is adjusted to reflect the Test Period revenue expected per the terms of contracts in effect during the Test Period. The corresponding impact on NPC is included in adjustment 5.1 and in the TAM.

Tab 4 – O&M Adjustments

Q. Please describe the information contained behind Tab 4 O&M Adjustments.

A. Tab 4 includes an O&M Expense Adjustment Index followed by a numerical summary and the specific adjustments. The O&M Expense Adjustment Index begins on page 4.0.1 with a brief overview of assumptions used to adjust operation, maintenance, administrative, and general expenses. The numerical summary (pages 4.0.2 to 4.0.3) identifies each adjustment made to actual expenses and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected

[10] *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).

FERC account(s), allocation factor(s), dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments made to O&M expense in Tab 4.

A. **Miscellaneous General Expense and Revenue (page 4.1) –** This adjustment removes certain miscellaneous expenses that should have been charged below the line to non-regulated expenses, and recognizes revenues from the Oregon Direct Access Opt Out amortization.[11] It also reallocates certain gains and losses on property sales and regulatory expenses to reflect the appropriate allocation.

Wage and Employee Benefits (page 4.2) – Labor-related costs for the Test Period are computed by adjusting salaries, incentives, health benefits, and costs associated with pension, post-retirement benefits, and post-employment benefits for changes expected beyond the actual costs experienced in the period ended June 2019.

Collective bargaining agreements are used to escalate union wages where increases are specified, while increases for non-union and exempt employees were based on actual or anticipated increases. Incentive compensation for non-union employees is included using a three-year average of the ratio of annual incentive expense to base wages. Pension expense and other employee benefit costs are adjusted to the planned expense for the Test Period, based on actuarial reports, where available, or by escalating actual costs. Please see the direct testimony of Ms. Nikki L. Kobliha for further discussion of the Company's pension expense.

Page 4.2.1 of the Report provides further description of the procedures used to compute Test Period labor costs. Page 4.2.2 contains a numerical summary of actual

[11] *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).

labor costs in the year ended June 2019 and summarizes the adjustments made to project costs through the Test Period. This summary is followed by detailed worksheets on pages 4.2.3 through 4.2.11.

Revenue-Sensitive Items & Uncollectible Accounts (page 4.3) – Uncollectible accounts expense is adjusted to the Test Period level by applying the historical uncollectible rate (Oregon uncollectible accounts expense in FERC Account 904 divided by Oregon general business revenues) to the normalized general business revenues in the Test Period. This adjustment also reflects pro forma changes to Franchise Tax, Resource Supplier Tax, and Public Utility Commission Fees based on the normalized level of general business revenue for the Test Period.

Insurance Expense (page 4.4) – In the 2010 Rate Case, the Commission authorized the Company to establish monthly accruals and associated reserve balances for self-insurance for transmission and distribution property losses, non-transmission and distribution (Non-T&D) property losses, and third-party liability losses.[12] The Commission ordered the accrual to begin on April 1, 2011, as a replacement for the expiration of the Company's captive insurance coverage with Berkshire Hathaway Energy Company (formerly known as MidAmerican Energy Holdings Company). The Oregon-allocated monthly accrual for property related losses was based on a 10-year average of actual property losses, with each year escalated by the Consumer Price Index (CPI) to the Test Period. The Oregon-allocated monthly accrual for third-party liability losses was established based on an annual average of historical insurance claim payments from April 2005 to December 2009.

[12] Order No. 10-473 at 5.

The adjustment in this case uses the Commission-approved methodology for self-insurance accruals from the 2010 Rate Case and every case since, updated for known and measurable changes for both property and liability losses. Premiums for both property and liability insurance have also been adjusted for known and measurable changes in the Test Period.

Consistent with the treatment from the 2010 Rate Case, the Company is using a 10-year average of property damages for the self-insurance reserve accrual, using the most recent 10-year time period. Total-Company Non-T&D property insurance premiums were $5.2 million for the 12 months ended June 2019 and will be reduced to $3.3 million for the Test Period.

Consistent with the treatment in the 2010 Rate Case, the third-party liability accrual in this case is calculated based on a five-year average of historical insurance events. Total-Company liability insurance premiums were $3.0 million for the 12 months ended June 2019 and will increase to $6.6 million for the Test Period.

Generation Overhaul Expense (page 4.5) – This adjustment normalizes generation overhaul expenses in the Base Period using a four-year average methodology. In this adjustment, overhaul expenses for the years ending June 2016 to June 2019 are restated to constant dollars to make them comparable prior to averaging.

Memberships and Subscriptions (page 4.6) – This adjustment removes expenses in excess of Commission policy as outlined by the Commission order in docket UE 94.[13] National and regional trade organizations are recognized at 75 percent.

[13] *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).

Incremental O&M (page 4.7) – This adjustment adds incremental O&M to the Base Period to bring it to the projected O&M level for the 12 months ending December 2021 by adding incremental O&M expenses for known and measurable changes in the Test Period. Specifically, this adjustment adds into results of operations incremental expenses associated with the new Pryor Mountain Wind Project and wildfire mitigation efforts. For details on the Pryor Mountain Wind Project, please refer to the direct testimony of Mr. Chad A. Teply, and for details on the Company's wildfire mitigation efforts, please refer to the direct testimony of Mr. David M. Lucas.

Paperless Bill Credit Adjustment (page 4.8) – This adjustment adds into test period results the pro forma reduction to revenues for the proposed paperless bill credit. For details on this proposal, please refer to the direct testimony of Ms. Melissa S. Nottingham.

Credit Facility Fees Adjustment (page 4.9) – The Company incurs banking fees consisting of upfront and quarterly commitment fees on revolving credit facilities which support the Company's Commercial Paper issuances by providing a secondary source of repayment for the Commercial Paper. This adjustment corrects the accounting for these fees.

Remove Non-Recurring Entries (page 4.10) – This adjustment removes accounting entries made to expense accounts during the Base Period that are non-recurring in nature or relate to a prior period. These transactions are removed in this adjustment from the results of operations to normalize the Test Period results. Details on the specific item in the adjustment can be found on page 4.10.1 of the Report.

O&M Escalation (page 4.11) – This adjustment increases non-labor expenses for projected inflation through the Test Period. Projected increases or decreases in costs are based on Global Insight, which provide a detailed assessment of the electric market both historically and into the future. The indices used are based solely on electric utility costs for materials and services, which exclude labor expense, according to the Uniform System of Accounts defined by FERC for major electric utilities.

The Global Insight indices are prepared at the FERC functional subcategory level and are denoted with their corresponding FERC account number. The individual FERC account level indices are then combined into broader indices representing operation, maintenance, or total O&M expenses. The Global Insight study used to prepare this filing was the third quarter 2019 forecast, released November 4, 2019. The Global Insight data is proprietary and subject to copyright protection, therefore the indices utilized in the Company's case are provided in Confidential Exhibit PAC/1306.

Tab 5 – Net Power Cost Adjustments

Q. Please describe the information contained behind Tab 5 Net Power Cost Adjustments.

A. Tab 5 includes adjustments to items that are generally related to NPC, but are addressed separately in the Company's TAM filing. Specifically, adjustment page 5.1, Net Power Costs relates solely to NPC and recovery of these costs is being sought in the TAM rather than the general rate case. This adjustment is included for modeling and computational purposes only. For example, the Test Period revenue requirement includes revenue sensitive items such as Franchise Tax, Resource Supplier Tax, and Public Utility Commission Fees that are calculated off total general business revenues, including those collected for the purpose of recovering costs included in the TAM.

The Net Power Cost Index on page 5.0.1 is a brief overview of assumptions used to adjust NPC-related items. The numerical summary (page 5.0.2) identifies each adjustment made to actual expenses and that adjustment's impact on overall revenue requirement. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 5.

A. **Net Power Cost Adjustment (page 5.1) –** This adjustment normalizes power costs by adjusting sales for resale, purchased power, wheeling, and fuel in a manner consistent with the contractual terms of sales and purchase agreements, as well as normal hydro and temperature conditions for the Test Period. The GRID study for this adjustment is based on forecasted loads for the Test Period. As previously described, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; NPC is not part of the revenue requirement for the general rate case.

Nodal Pricing Model Adjustment (page 5.2)—This adjustment adds in pro forma capital and incremental O&M expenses for the new Nodal Pricing Model as agreed to in PacifiCorp's Nodal Pricing Model Memorandum of Understanding.[14] Please refer to the testimony of Mr. Michael G. Wilding for more information on the Nodal Pricing Model.

Tab 6 – Depreciation and Amortization Expense Adjustments

Q. Please describe the information contained behind Tab 6 Depreciation and Amortization Adjustments.

A. Tab 6 includes the Depreciation and Amortization Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 6.0.1 is a brief overview of assumptions used to adjust overall depreciation and amortization expense and reserve. The numerical summary (page 6.0.2) identifies each adjustment made to actual results and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 6.

A. **Depreciation and Amortization Expense (page 6.1) –** This adjustment reflects the incremental depreciation expense associated with the capital additions included in Adjustment 8.5, Pro Forma Plant Additions, and calculates the depreciation expense for the proposed depreciation rates in docket UM 1968 effective January 1, 2021. The annualized level of depreciation and amortization expense for the Test Period is calculated by first applying the current composite depreciation and amortization rates

[14] *In the matter of PacifiCorp, dba Pacific Power, Request to Initiate an Investigation of MultiJurisdictional Issues and Approve an InterJurisdictional Cost Allocation Protocol*, Docket No. UM 1050, Exhibit PAC/101, Appendix D (Dec. 3, 2019).

to the December 2020 pro forma plant balances. The current composite rates used are those approved by the Commission in docket UM 1647, which became effective on January 1, 2014.[15] The depreciation expense is then updated for the proposed depreciation rates filed in docket UM 1968, which the Company has requested become effective on January 1, 2021, the beginning of the Test Period. The proposed depreciation rates include the updated decommissioning study for most of the Company's coal generation fleet as discussed in the supplemental testimonies of Mr. Teply and Mr. McDougal in UM 1968. The proposed rates in UM 1968 increase Oregon's allocated share of depreciation and amortization expense by $63.6 million. The detailed calculation of the depreciation and amortization expense is provided on pages 6.1 through 6.1.17.

Depreciation and Amortization Reserve (page 6.2) – This adjustment steps forward the depreciation and amortization reserve from the Base Period to a December 2020 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to Base Period balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2019, to December 31, 2020. An incremental reserve amount has been added to the December 31, 2020 balance, to reflect the depreciation expense due to the proposed depreciation study rates being added in through adjustment 6.1. The reserve balance calculations are detailed on pages 6.2 to 6.2.13.

[15] *In the matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates*, Docket No. UM 1647, Order No. 13-347 (Sept. 25, 2003).

Depreciation Allocation Correction Adjustment (page 6.3) – 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. This deferred amount is reflected in historical data on a system-allocated basis, but should only be situs-assigned to Wyoming, Utah, and Idaho. This adjustment removes the steam related deferred depreciation expense from historical data for Oregon's results of operations. Also being removed in this adjustment is the steam plant give-back reversal in Oregon established as part of the 2012 depreciation study. This give-back amount does not need to be incrementally added back into results, since the current rate case incorporates into rates the new depreciation rates through Adjustments 6.1 (Depreciation and Amortization Expense) and 6.2 (Depreciation and Amortization Reserves) and in doing so, will re-set annual depreciation expense to appropriate levels in the Test Period.

Other Plant Closure Costs Adjustment (page 6.4) – This adjustment reflects the recovery of Other Plant Closure Costs included in the updated decommissioning study discussed in Mr. McDougal's supplemental testimony in UM 1968. The Company proposes collecting the identified costs over the remaining life of each respective generation plant.

Additionally, this adjustment includes accelerated depreciation and reclamation costs for the Bridger Mine incremental to the amounts included in the cost of coal delivered to the Jim Bridger Plant. These costs will be recovered over the remaining depreciable life for Oregon customers of the Jim Bridger Plant.

The above amounts to be collected from Oregon customers will be deferred to a regulatory liability, which will be debited with Oregon's share of Other Plant Closure costs when actual plant retirement occurs and Oregon's share of reclamation costs when the Bridger Mine closes. This treatment will allow the Company to recover closure costs of coal generation plants and the Bridger Mine while meeting the Senate Bill (SB) 1547 requirement of removing coal from Oregon electric utility rates prior to January 1, 2030.

Tab 7 – Tax Adjustments

Q. Please describe the information contained behind Tab 7 Tax Adjustments.

A. Tab 7 includes the Tax Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index (page 7.0.1) contains a brief overview of the tax adjustments included in this case. The numerical summary on pages 7.0.2 and 7.0.3 identifies each adjustment made to the various tax components and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 7.

A. **Interest True-Up (page 7.1) –** This adjustment details the adjustment to interest expense required to synchronize the Test Period interest expense with Test Period rate base. This is done by multiplying normalized net rate base by the Company's weighted cost of debt in this case.

Property Tax Expense (page 7.2) – Property tax expense for the Test Period is computed by adjusting accruals from the Base Period for known or anticipated changes in the assessed values of the Company's operating property and the corresponding effect such changes will have on property tax expense for the Test Period. For additional information on the Company's property tax estimation procedures and methodologies, please refer to Confidential Exhibit PAC/1303.

Production Tax Credit (PTC) (page 7.3) – The Company is entitled to recognize federal income tax credits as a result of placing renewable generating plants in service. The tax credit is based on the kilowatt-hours generated by the plants, and the credit can be taken for the first 10 years of generation from qualifying property. The PTC calculation reflects the credit based on the qualifying production as modeled for the Test Period NPC study. Customers receive the benefit of the PTCs in the Company's annual TAM filing. As with NPC in Adjustment 5.1, this adjustment is included for the purposes of calculating an overall revenue requirement only.

PowerTax Accumulated Deferred Income Tax (ADIT) Balance (page 7.4) – This adjustment normalizes ADIT balances to an estimated pro forma level of rate base balance for the Test Period. Additional line item detail is included in the tax model that is provided with the Company's electronic workpapers.

Pro Forma Tax Balances Adjustment (page 7.5) – This adjustment normalizes the Schedule M items, deferred tax expense and related ADIT balances to an estimated pro forma level of expense for the Test Period. Additional line item detail is included in the tax model that is provided with the Company's electronic work papers.

Wyoming Wind Generation Tax (page 7.6) – This adjustment normalizes the Wyoming Wind Generation Tax, which became effective January 1, 2012, into Test Period results. The Wyoming Wind Generation Tax is an excise tax levied upon production of electricity from wind resources in the state of Wyoming. The tax is on the production of any electricity produced from wind resources for sale or trade on or after January 1, 2012, and is to be paid by the entity producing the electricity. New wind facilities are exempt from the tax for three years following the date the facility first produces electricity for sale. The tax is one dollar for each megawatt-hour (MWh) of electricity produced from wind resources at the point of interconnection with an electric transmission line.

Allowance for Funds Used During Construction (AFUDC) Equity (page 7.7) – This adjustment reflects the appropriate level of AFUDC equity into regulated results to align the tax schedule M with regulatory income. Per Commission Order 10-022, AFUDC equity in this case is included using flow-through tax treatment.[16]

Tax Cuts and Jobs Act Adjustment (page 7.8) – This adjustment reflects the removal of the non-protected tax deferral balances as a result of the TCJA that was enacted on December 22, 2017. The corporate income tax rate was reduced from 35 percent to 21 percent effective January 1, 2018. The related non-protected tax deferral balances are being removed from the base period and, as described further below, returned to customers via a separate tariff rider proposed as part of this rate case. This adjustment also reflects the appropriate level of protected Excess Deferred Income Tax (EDIT) amortization using the Reverse South Georgia Method. Please

[16] *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).

refer to the testimony of Ms. Kobliha for further information on the impacts of the TCJA.

Q. Please describe the amortization of the deferred TCJA balances.

A. The Company is proposing a three-year amortization of the remaining deferred TCJA balances, including the balance of deferred current tax benefits due to the reduced tax rate. This amortization will result in a $24.9 million annual rate credit for Oregon customers for three years. Please see Exhibit PAC/1313 for the details of the amortization schedule. For additional information on the Federal Tax Act Adjustment that will be used to return this credit to customers, please see the testimony of Mr. Robert M. Meredith.

Tab 8 – Rate Base Adjustments

Q. Please describe the information contained behind Tab 8 Rate Base Adjustments.

A. Tab 8 includes the Rate Base Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 8.0.1 begins with a brief overview of assumptions used to adjust rate base components. The numerical summary (pages 8.0.2 to 8.0.4) identifies each adjustment made to actual rate base and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe each of the adjustments to the historical rate base balances.

A. **Cash Working Capital (page 8.1) –** This adjustment supports the calculation of cash working capital included in rate base based on the normalized results of operations for the Test Period. Total cash working capital is calculated by multiplying jurisdictional net lag days by the average daily cost of service. Net lag days in this case are based on a lead lag study prepared by PacifiCorp using calendar year 2015 information. An electronic version of the lead lag study is included as part of the Company's workpapers.

Trapper Mine Rate Base (page 8.2) – The Company owns a 21.4 percent interest in the Trapper Mine, which provides coal to the Craig generating plant. The normalized coal cost of Trapper includes all O&M costs but does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine plant investment to the rate base and reflects net plant to recognize the depreciation of the investment over time. This adjustment also walks the reclamation liability forward to December 2020. This adjustment was stipulated to and approved in docket UE 111[17] and has been included in all Oregon rate case filings since.

Jim Bridger Mine Rate Base (page 8.3) – The Company owns a two-thirds interest in the Bridger Coal Company, which supplies coal to the Jim Bridger generating plant. The Company's investment in Bridger Coal Company is recorded on the books of Pacific Minerals, Inc. Because of this ownership arrangement, the coal mine investment is not included in electric plant in service. This adjustment is necessary to properly reflect the Bridger Coal Company investment in rate base for the Company to earn a return on its investment. The normalized coal costs for Bridger Coal Company in NPC include the O&M costs of the mine but provide no return on investment. This adjustment adds the Company's portion of the pro forma

[17] 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).

December 31, 2020, net plant balance to rate base. This adjustment was stipulated to and approved in docket UE 111 and has been included in all Oregon rate case filings since.[18]

Customer Advances for Construction (page 8.4) – Customer advances were recorded in the Base Period to a corporate cost center location rather than state-specific locations. This adjustment corrects the allocation factors of customer advances.

Pro Forma Plant Additions and Retirements (page 8.5) – To reasonably represent the cost of system infrastructure required to serve customers, the Company has identified capital projects that will be used and useful by December 31, 2020.

Capital additions by FERC functional category are listed on pages 8.5.18 to 8.5.25, indicating the in-service date and amount by project. This adjustment is based on plant balances as of December 31, 2020. As described earlier in my testimony, the accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements. Projects over $10 million (total-company basis) are described on pages 8.5.27 through 8.5.30 of the Report. Not included in this adjustment are the wind repowering projects, Adjustment 8.13, and the new wind generation resources and associated transmission included in Energy Vision 2020, Adjustment 8.14.

Miscellaneous Rate Base (page 8.6) – This adjustment reflects the change in the fuel stock balance from the Base Period to the Test Period. This adjustment also reflects the working capital deposits that are offsets to fuel stock costs. In addition, balances

[18] 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).

for prepaid overhauls at the Lake Side, Chehalis, and Currant Creek natural gas plants are walked forward to reflect payments and transfers of capital to electric plant in service on a 13-month average basis through the Test Period. This adjustment was included in the stipulated settlement and approved in the Company's 2013 Rate Case.[19]

Plant Held for Future Use (PHFU) (page 8.7) – This adjustment removes all PHFU assets from FERC account 105. The Company is making this adjustment in compliance with Order 01-787.[20]

Regulatory Asset and Liability Amortization (page 8.8) – This adjustment normalizes regulatory assets and liabilities from the Base Period to the Test Period. In addition, the Company is proposing to begin amortization of deferred FERC Open Access Transmission Tariff (OATT) revenues from 2017 through 2020, net of the undepreciated equipment balances as a result of the all-party stipulation in docket UE 369 and as proposed for the repowering of Foote Creek in this filing, starting on the rate effective date of this case.[21] The Company is proposing an amortization period of three years.

Remove Rolling Hills (page 8.9) – This adjustment removes the gross plant, accumulated depreciation, and O&M amounts related to the Rolling Hills wind resource from the Base Period. Depreciation expense for Rolling Hills is removed in

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[19] Order No. 13-474 at 3 and App. A at 18.
[20] *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)
[21] *In the matter of PacifiCorp dba Pacific Power 2020 Renewable Adjustment Clause*, Docket No. 369, Stipulation and Joint Testimony (Jan. 31, 2020).

Adjustment 6.1, Depreciation/Amortization Expense Adjustment. This treatment is consistent with Order 08-548.[22]

Carbon Plant Retirement (page 8.10) – 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. This deferred amount includes a portion representing the accelerated depreciation expense associated with the early retirement of the Carbon plant. The Carbon plant was retired in April 2015. The deferral and amortization continues to be recorded in the Company's accounting books in the Base Period. However, this deferred expense is being recorded on a system-allocated basis, when it should be situs-assigned to Utah, Idaho, and Wyoming only. This adjustment removes the system-allocated amount from Oregon's historical results of operations.

The Company continues to carry a regulatory liability for Carbon Plant decommissioning that has yet to be returned to Oregon customers. This adjustment includes the Company's proposal in the 2018 Depreciation Study to return this balance for the benefit of Oregon customers over a five-year amortization period. For additional details on the Carbon Plant decommissioning balance, please see the direct testimony of Mr. McDougal in the 2018 Depreciation Study, docket UM 1968.

Pension and Other Post-retirement Plan Balances Removal (page 8.11) – This adjustment removes the Company's net prepaid asset associated with its pension and other post-retirement welfare plans, net of associated accumulated deferred income

[22] *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).

taxes in unadjusted results. Per Order 15-226 in docket UM 1633, the net pension and post-retirement prepaid is not to be included in rate base for Oregon.[23]

Deer Creek Mine Adjustment (page 8.12) – Order 15-161 in docket UM 1712 addressed closure of the Deer Creek mine located in Utah and ruled on several issues.[24] This adjustment removes the Deer Creek Unrecovered Plant Regulatory Assets from results because these amounts have been recovered through a separate tariff rider.

Order 15-161 also authorized the creation of a deferred account to track the Deer Creek Mine closure costs and costs due to Retiree Medical Obligation Settlement Loss to be addressed in the subsequent ratemaking proceedings.[25] The Company is proposing in the current rate case to include all costs and savings in the Deer Creek deferral account in rate base to be amortized over three years.

Repowering Projects Capital Additions (page 8.13) – This pro forma adjustment adds the capital additions and depreciation amounts for the wind repowering projects set to occur before December 2020. Included in this adjustment are the repowering projects included in the Company's Renewable Adjustment Clause filings for the 2019 and 2020 repowering projects, dockets UE 352 and UE 369, as well as the repowering of Foote Creek I. Per the approved stipulation in docket UE 352,[26] the net book value of replaced equipment included in that filing has been offset with excess deferred income tax balances as a result of the TCJA. As proposed and agreed

[23] *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).

[24] Order No. 15-161.

[25] *Id.* at 1, 10.

[25] *In the matter of PacifiCorp dba Pacific Power, 2019 Renewable Adjustment Clause,* Docket No. 352, Order No. 19-304 (Sept. 16, 2019).

to in the all-party stipulation filed on January 31, 2020, in docket UE 369, the net book value of replaced equipment at Glenrock III and Dunlap is being offset by deferred revenues related to the Company's OATT. This same treatment is being proposed for the net book value of replaced equipment in the repowering of Foote Creek I. For additional details on the repowering of Foote Creek I, please refer to Mr. Timothy J. Hemstreet's testimony.

EV 2020 Capital Additions (page 8.14) – This pro forma adjustment adds the capital additions and depreciation amounts for the Energy Vision 2020 new wind generation projects and associated transmission set to occur before December 2020. For additional details on the new wind and transmission, please refer to Mr. Link's, Mr. Teply's, and Mr. Richard A. Vail's testimony.

Cholla Unit 4 Retirement (page 8.15) – This adjustment removes from rate base balances related to Cholla Unit 4, which is to be retired on December 31, 2020. It also removes from expense, depreciation expense and costs related to the O&M of this generation resource.

Remaining unrecovered plant, construction work-in-progress, materials and supplies and other costs related to the closure of Cholla Unit 4 have been recorded in regulatory assets. The Company proposes to recover the Cholla regulatory assets and estimated decommissioning costs not already collected in depreciation rates in a separate tariff adjustment, the Generation Plant Removal Adjustment discussed in Ms. Lockey's testimony, beginning January 2021 through April 2025, the previous end-of-life for this unit. Estimated decommissioning costs have been included using currently available estimates. However, a decommissioning study for the Cholla plant is expected to be completed in Spring 2020, at which time these costs will be updated. The Company proposes a carrying charge on the regulatory assets equal to the pre-tax weighted average cost of capital as approved in this rate case. Please see Exhibit PAC/1312 for the details of the amortization schedule.

Klamath Facilities Capital Additions (page 8.16) – As previously discussed in my testimony, the timing of when the Klamath Facilities will cease operations is uncertain. In order to maintain the facilities and ensure compliance with dam safety requirements, the Company will continue to make capital expenditures on these facilities. This adjustment adds in the capital additions that will be in service through December 31, 2020, associated accumulated depreciation as of year-end 2020 and an annual amount of depreciation expense assuming a 20 percent depreciation rate as discussed above.

Tab 9 – 2020 Protocol ECD

Q. Please describe the information contained behind Tab 9.

A. Tab 9 demonstrates the derivation of the 2020 Protocol ECD amount included in the current rate case.

Q. Please explain the changes to the ECD adjustment in the 2020 Protocol.

A. The Fixed ECD, as used in the 2017 Protocol, will continue for Idaho at $836,000 through the end of 2023. The Dynamic ECD, as used in the 2010 Protocol, will continue for Oregon through the end of 2023, capped at $11,000,000. No ECD adjustment exists for Utah or California. In Wyoming, the ECD will terminate December 31, 2020.

Q. What is the Dynamic ECD?

A. The Dynamic ECD measures the embedded cost differentials between the production costs of pre-2005 resources, as defined in the 2010 Protocol, and the production cost of west hydro-electric resources and certain Mid-Columbia Contracts. The first part is computed by taking PacifiCorp's production costs related to pre-2005 resources, expressed in dollars per MWh, compared to production costs of west-side hydro-electric resources expressed in dollars per MWh with the difference multiplied by the hydro-electric resources' MWhs of production. The second part is computed by taking the differential between the pre-2005 resources' dollars per MWh compared to Mid-Columbia Contracts' costs on a dollars per MWh multiplied by the Mid-Columbia Contracts' MWhs.

Tab 10 – Allocation Factors

Q. Please describe the information contained behind Tab 10 Allocation Factors.

A. Tab 10 Allocation Factors summarizes the derivation of the inter-jurisdictional allocation factors using the 2020 Protocol.

Tabs B1 to B20

Q. Please describe the information contained behind Tabs B1 to B-20.

A. Tabs B1 through B20 contain the historical results for the Base Period and are organized by major FERC function. The data contained in this section of the Report matches the unadjusted data found under Tab 2 – Results of Operations.

VI. CONCLUSION

Q. Please summarize your testimony.

A. I recommend that the Commission approve the requested $78.0 million increase and non-NPC revenue requirement of $1,045.7 million.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/1301
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Revenue Requirement Summary

February 2020

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

		(1)	(2)	(3)	(4)	(5)	(6)
			(3) - (1)	Ref. Page 1.3	Ref. Page 1.2	Ref. Page 1.1	(3) + (4) + (5)
					TAM	**GRC**	
		NPC-Related Results	Non-NPC Related Results	Total Adjusted Results	NPC-Related Under Recovery	Requested Non-NPC Related Price Change	Total Normalized Results with Price Change
1	Operating Revenues:						
2	General Business Revenues	341,185,758	967,698,957	1,308,884,715	(49,210,532)	77,993,178	1,337,667,361
3	Interdepartmental		-	-			-
4	Special Sales	73,285,143	-	73,285,143			73,285,143
5	Other Operating Revenues		50,008,283	50,008,283			50,008,283
6	Total Operating Revenues	414,470,901	1,017,707,240	1,432,178,141	(49,210,532)	77,993,178	1,460,960,786
7							
8	Operating Expenses:						
9	Steam Production	156,671,450	90,638,928	247,310,378			247,310,378
10	Nuclear Production		-	-			-
11	Hydro Production		11,814,928	11,814,928			11,814,928
12	Other Power Supply	237,044,768	20,379,809	257,424,578			257,424,578
13	Transmission	36,165,687	19,850,575	56,016,262			56,016,262
14	Distribution		69,726,150	69,726,150			69,726,150
15	Customer Accounting		30,202,104	30,202,104		110,860	30,312,965
16	Customer Service & Info		6,141,331	6,141,331			6,141,331
17	Sales		-	-			-
18	Administrative & General		41,472,852	41,472,852			41,472,852
19							
20	Total O&M Expenses	429,881,905	290,226,678	720,108,582	-	110,860	720,219,443
21							
22	Depreciation		316,560,184	316,560,184			316,560,184
23	Amortization		21,091,819	21,091,819			21,091,819
24	Taxes Other Than Income		86,353,112	86,353,112		828,595	87,181,707
25	Income Taxes - Federal	(51,822,679)	41,235,661	(10,587,018)	(9,865,039)	15,446,652	(5,005,405)
26	Income Taxes - State	(699,660)	9,339,759	8,640,100	(2,234,158)	3,498,239	9,904,180
27	Income Taxes - Def Net		(11,537,533)	(11,537,533)			(11,537,533)
28	Investment Tax Credit Adj.		-	-			-
29	Misc Revenue & Expense		546,879	546,879			546,879
30							
31	Total Operating Expenses:	377,359,566	753,816,560	1,131,176,126	(12,099,197)	19,884,346	1,138,961,275
32							
33	Operating Rev For Return:	37,111,335	263,890,680	301,002,015	(37,111,335)	58,108,832	321,999,512
34							
35	Rate Base:						
36	Electric Plant In Service		8,433,754,519	8,433,754,519			8,433,754,519
37	Plant Held for Future Use		-	-			-
38	Misc Deferred Debits		67,302,496	67,302,496			67,302,496
39	Elec Plant Acq Adj		1,749,820	1,749,820			1,749,820
40	Pension		-	-			-
41	Prepayments		8,805,023	8,805,023			8,805,023
42	Fuel Stock		42,986,611	42,986,611			42,986,611
43	Material & Supplies		73,659,471	73,659,471			73,659,471
44	Working Capital		8,091,631	8,091,631			8,091,631
45	Weatherization Loans		(1,363)	(1,363)			(1,363)
46	Misc Rate Base		-	-			-
47							
48	Total Electric Plant:	-	8,636,348,208	8,636,348,208			8,636,348,208
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec		(3,200,067,136)	(3,200,067,136)			(3,200,067,136)
52	Accum Prov For Amort		(190,276,927)	(190,276,927)			(190,276,927)
53	Accum Def Income Tax		(591,816,891)	(591,816,891)			(591,816,891)
54	Unamortized ITC		0	0			0
55	Customer Adv For Const		(13,802,322)	(13,802,322)			(13,802,322)
56	Customer Service Deposits		-	-			-
57	Misc Rate Base Deductions		(445,680,643)	(445,680,643)			(445,680,643)
58							
59	Total Rate Base Deductions	-	(4,441,643,918)	(4,441,643,918)			(4,441,643,918)
60							
61	Total Rate Base:	-	4,194,704,290	4,194,704,290			4,194,704,290
62							
63	Return on Rate Base			7.176%			7.676%
64							
65	Return on Equity			9.265%			10.200%

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

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	967,698,957	77,993,178	1,045,692,135
3	Interdepartmental	-		-
4	Special Sales	-		-
5	Other Operating Revenues	50,008,283		50,008,283
6	Total Operating Revenues	1,017,707,240	77,993,178	1,095,700,417
7				
8	Operating Expenses:			
9	Steam Production	90,638,928		90,638,928
10	Nuclear Production	-		-
11	Hydro Production	11,814,928		11,814,928
12	Other Power Supply	20,379,809		20,379,809
13	Transmission	19,850,575		19,850,575
14	Distribution	69,726,150		69,726,150
15	Customer Accounting	30,202,104	110,860	30,312,965
16	Customer Service & Info	6,141,331		6,141,331
17	Sales	-		-
18	Administrative & General	41,472,852		41,472,852
19				
20	Total O&M Expenses	290,226,678	110,860	290,337,538
21				
22	Depreciation	316,560,184		316,560,184
23	Amortization	21,091,819		21,091,819
24	Taxes Other Than Income	86,353,112	828,595	87,181,707
25	Income Taxes - Federal	41,235,661	15,446,652	56,682,313
26	Income Taxes - State	9,339,759	3,498,239	12,837,998
27	Income Taxes - Def Net	(11,537,533)		(11,537,533)
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	546,879		546,879
30				
31	Total Operating Expenses:	753,816,560	19,884,346	773,700,906
32				
33	Operating Rev For Return:	263,890,680	58,108,832	321,999,512
34				
35	Rate Base:			
36	Electric Plant In Service	8,433,754,519		8,433,754,519
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	67,302,496		67,302,496
39	Elec Plant Acq Adj	1,749,820		1,749,820
40	Pension	-		-
41	Prepayments	8,805,023		8,805,023
42	Fuel Stock	42,986,611		42,986,611
43	Material & Supplies	73,659,471		73,659,471
44	Working Capital	8,091,631		8,091,631
45	Weatherization Loans	(1,363)		(1,363)
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	8,636,348,208		8,636,348,208
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,200,067,136)		(3,200,067,136)
52	Accum Prov For Amort	(190,276,927)		(190,276,927)
53	Accum Def Income Tax	(591,816,891)		(591,816,891)
54	Unamortized ITC	0		0
55	Customer Adv For Const	(13,802,322)		(13,802,322)
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	(445,680,643)		(445,680,643)
58				
59	Total Rate Base Deductions	(4,441,643,918)		(4,441,643,918)
60				
61	Total Rate Base:	4,194,704,290		4,194,704,290
62				
63	Return on Rate Base	6.291%		7.676%
64				
65	Return on Equity	7.612%		10.200%
66				
67	TAX CALCULATION:			
68	Operating Revenue	302,928,567	77,053,723	379,982,290
69	Other Deductions			
70	Interest (AFUDC)	(18,867,154)	-	(18,867,154)
71	Interest	93,235,859	-	93,235,859
72	Schedule "M" Additions	397,826,658	-	397,826,658
73	Schedule "M" Deductions	420,664,954	-	420,664,954
74	Income Before Tax	205,721,566	77,053,723	282,775,289
75				
76	State Income Taxes	9,339,759	3,498,239	12,837,998
77	Taxable Income	196,381,807	73,555,484	269,937,291
78				
79	Federal Income Taxes + Other	41,235,661	15,446,652	56,682,313

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

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	341,185,758	(49,210,532)	291,975,226
3	Interdepartmental	-		-
4	Special Sales	73,285,143		73,285,143
5	Other Operating Revenues	-		-
6	Total Operating Revenues	414,470,901	(49,210,532)	365,260,369
7				
8	Operating Expenses:			
9	Steam Production	156,671,450		156,671,450
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	237,044,768		237,044,768
13	Transmission	36,165,687		36,165,687
14	Distribution	-		-
15	Customer Accounting	-	-	-
16	Customer Service & Info	-		-
17	Sales	-		-
18	Administrative & General	-		-
19				
20	Total O&M Expenses	429,881,905	-	429,881,905
21				
22	Depreciation	-		-
23	Amortization	-		-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	(51,822,679)	(9,865,039)	(61,687,718)
26	Income Taxes - State	(699,660)	(2,234,158)	(2,933,818)
27	Income Taxes - Def Net	-		-
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	-		-
30				
31	Total Operating Expenses:	377,359,566	(12,099,197)	365,260,369
32				
33	Operating Rev For Return:	37,111,335	(37,111,335)	-
34				
35	Rate Base:			
36	Electric Plant In Service	-		-
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	-		-
39	Elec Plant Acq Adj	-		-
40	Pension	-		-
41	Prepayments	-		-
42	Fuel Stock	-		-
43	Material & Supplies	-		-
44	Working Capital	-		-
45	Weatherization Loans	-		-
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	-		-
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-		-
52	Accum Prov For Amort	-		-
53	Accum Def Income Tax	-		-
54	Unamortized ITC	-		-
55	Customer Adv For Const	-		-
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	-		-
58				
59	Total Rate Base Deductions	-		-
60				
61	Total Rate Base:	-		-
62				
63	Return on Rate Base	N/A		N/A
64				
65	Return on Equity	N/A		N/A
66				
67	TAX CALCULATION:			
68	Operating Revenue	(15,411,004)	(49,210,532)	(64,621,536)
69	Other Deductions			
70	Interest (AFUDC)	-	-	-
71	Interest	-	-	-
72	Schedule "M" Additions	-	-	-
73	Schedule "M" Deductions	-	-	-
74	Income Before Tax	(15,411,004)	(49,210,532)	(64,621,536)
75				
76	State Income Taxes	(699,660)	(2,234,158)	(2,933,818)
77	Taxable Income	(14,711,344)	(46,976,374)	(61,687,718)
78				
79	Federal Income Taxes + Other	(51,822,679)	(9,865,039)	(61,687,718)

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL Twelve Months
Ending December 31, 2021

COMBINED TAM AND GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,308,884,715	28,782,645	1,337,667,361
3	Interdepartmental	-		
4	Special Sales	73,285,143		
5	Other Operating Revenues	50,008,283		
6	Total Operating Revenues	1,432,178,141		
7				
8	Operating Expenses:			
9	Steam Production	247,310,378		
10	Nuclear Production	-		
11	Hydro Production	11,814,928		
12	Other Power Supply	257,424,578		
13	Transmission	56,016,262		
14	Distribution	69,726,150		
15	Customer Accounting	30,202,104	110,860	30,312,965
16	Customer Service & Info	6,141,331		
17	Sales	-		
18	Administrative & General	41,472,852		
19				
20	Total O&M Expenses	720,108,582		
21				
22	Depreciation	316,560,184		
23	Amortization	21,091,819		
24	Taxes Other Than Income	86,353,112	828,595	87,181,707
25	Income Taxes - Federal	(10,587,018)	5,581,613	(5,005,405)
26	Income Taxes - State	8,640,100	1,264,081	9,904,180
27	Income Taxes - Def Net	(11,537,533)		
28	Investment Tax Credit Adj.	-		
29	Misc Revenue & Expense	546,879		
30				
31	Total Operating Expenses:	1,131,176,126	7,785,149	1,138,961,275
32				
33	Operating Rev For Return:	301,002,015	20,997,497	321,999,512
34				
35	Rate Base:			
36	Electric Plant In Service	8,433,754,519		
37	Plant Held for Future Use	-		
38	Misc Deferred Debits	67,302,496		
39	Elec Plant Acq Adj	1,749,820		
40	Pensions	-		
41	Prepayments	8,805,023		
42	Fuel Stock	42,986,611		
43	Material & Supplies	73,659,471		
44	Working Capital	8,091,631		
45	Weatherization Loans	(1,363)		
46	Misc Rate Base	-		
47				
48	Total Electric Plant:	8,636,348,208	-	8,636,348,208
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,200,067,136)		
52	Accum Prov For Amort	(190,276,927)		
53	Accum Def Income Tax	(591,816,891)		
54	Unamortized ITC	0		
55	Customer Adv For Const	(13,802,322)		
56	Customer Service Deposits	-		
57	Misc Rate Base Deductions	(445,680,643)		
58				
59	Total Rate Base Deductions	(4,441,643,918)	-	(4,441,643,918)
60				
61	Total Rate Base:	4,194,704,290	-	4,194,704,290
62				
63	Return on Rate Base	7.176%		7.676%
64				
65	Return on Equity	9.265%		10.200%
66				
67	TAX CALCULATION:			
68	Operating Revenue	287,517,564	27,843,190	315,360,754
69	Other Deductions			
70	Interest (AFUDC)	(18,867,154)	-	(18,867,154)
71	Interest	93,235,859	-	93,235,859
72	Schedule "M" Additions	397,826,658	-	397,826,658
73	Schedule "M" Deductions	420,664,954	-	420,664,954
74	Income Before Tax	190,310,563	27,843,190	218,153,753
75				
76	State Income Taxes	8,640,100	1,264,081	9,904,180
77	Taxable Income	181,670,463	26,579,110	208,249,573
78				
79	Federal Income Taxes + Other	(10,587,018)	5,581,613	(5,005,405)

Pacificorp
Oregon General Rate Case Adjustment Summary
Twelve Months Ending December 31, 2021

	Exhibit PAC/1302		Exhibit PAC/1302			
			Tab 3	Tab 4	Tab 5	Tab 6
	TOTAL COMPANY UNADJUSTED RESULTS JUNE 2019	OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2019	Revenue Adjustments	O&M Adjustments	Net Power Cost Adjustments	Depreciation & Amortization Adjustments
1 Operating Revenues:						
2 General Business Revenues	4,738,801,365	1,262,527,098	44,630,291	1,727,327	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	243,934,081	59,812,893	-	-	13,472,250	-
5 Other Operating Revenues	177,063,148	45,048,206	1,703,647	(1,373,862)	-	-
6 Total Operating Revenues	5,159,798,594	1,367,388,196	46,333,938	353,465	13,472,250	-
7						
8 Operating Expenses:						
9 Steam Production	1,099,966,583	280,291,135	-	4,699,824	(35,024,379)	3,925,862
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	42,311,811	11,010,647	-	732,670	-	71,612
12 Other Power Supply	1,023,059,582	270,418,727	-	3,155,329	(20,239,216)	47,561
13 Transmission	212,793,850	55,389,954	-	1,215,813	(627,267)	37,762
14 Distribution	200,837,597	60,083,160	-	9,470,192	-	172,798
15 Customer Accounting	82,050,225	27,728,842	-	2,406,815	-	66,448
16 Customer Service & Info	99,292,578	5,678,204	-	450,160	-	12,967
17 Sales	-	-	-	-	-	-
18 Administrative & General	144,701,044	42,342,058	-	2,337,441	-	57,518
19						
20 Total O&M Expenses	2,905,013,270	752,942,727	-	24,468,244	(55,890,862)	4,392,527
21						
22 Depreciation	724,543,948	202,457,473	-	-	-	89,338,517
23 Amortization	53,602,343	14,431,373	-	-	45,829	8,409,854
24 Taxes Other Than Income	199,541,666	76,539,794	-	1,106,296	-	-
25 Income Taxes - Federal	205,103,291	53,666,191	9,287,901	(5,241,091)	13,832,769	(4,153,371)
26 Income Taxes - State	56,734,959	14,830,341	2,103,452	(1,186,962)	3,132,739	(940,624)
27 Income Taxes - Def Net	(183,345,084)	(19,234,974)	-	-	74,031	(18,836,403)
28 Investment Tax Credit Adj.	(2,943,987)	-	-	-	-	-
29 Misc Revenue & Expense	(3,327,067)	(372,574)	-	919,453	-	-
30						
31 Total Operating Expenses:	3,954,923,338	1,095,260,350	11,391,353	20,065,939	(38,805,494)	78,210,500
32						
33 Operating Rev For Return:	1,204,875,256	272,127,846	34,942,585	(19,712,474)	52,277,744	(78,210,500)
34						
35 Rate Base:						
36 Electric Plant In Service	28,210,093,332	7,705,361,496	-	-	1,040,905	-
37 Plant Held for Future Use	26,421,395	10,699,976	-	-	-	-
38 Misc Deferred Debits	852,539,521	185,642,803	-	-	-	-
39 Elec Plant Acq Adj	26,756,854	4,238,395	-	-	-	-
40 Pensions	2,485,363	676,399	-	-	-	-
41 Prepayments	46,540,395	8,805,023	-	-	-	-
42 Fuel Stock	184,750,079	46,375,019	-	-	-	-
43 Material & Supplies	249,437,716	75,382,743	-	-	-	-
44 Working Capital	49,534,022	16,235,238	107,671	180,973	(367,923)	(7,146,628)
45 Weatherization Loans	(8,425,958)	(1,363)	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	29,640,132,719	8,053,415,730	107,671	180,973	672,983	(7,146,628)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(10,032,916,685)	(2,903,746,581)	-	-	-	(205,275,908)
52 Accum Prov For Amort	(618,766,978)	(180,648,350)	-	-	-	(9,628,577)
53 Accum Def Income Tax	(4,311,827,079)	(1,121,847,609)	-	-	(81,517)	5,061,385
54 Unamortized ITC	(297,497)	(63,124)	-	-	-	-
55 Customer Adv For Const	(61,656,010)	(16,322,786)	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(655,284,072)	(114,407,804)	-	-	-	-
58						
59 Total Rate Base Deductions	(15,680,748,321)	(4,337,036,255)	-	-	(81,517)	(209,843,100)
60						
61 Total Rate Base:	13,737,172,111	3,716,379,475	107,671	180,973	591,466	(216,989,729)
62						
63 Return on Rate Base		7.322%	0.940%	-0.531%	1.405%	-1.668%
64						
65 Return on Equity		9.539%	1.756%	-0.992%	2.625%	-3.117%
66						
67 TAX CALCULATION:						
68 Operating Revenue		321,389,404	46,333,938	(26,140,528)	69,317,284	(102,140,898)
69 Other Deductions						
70 Interest (AFUDC)		(13,004,380)	-	-	-	-
71 Interest		82,633,220	2,387	4,011	13,111	(4,809,836)
72 Schedule "M" Additions		311,249,659	-	-	45,829	76,612,482
73 Schedule "M" Deductions		236,350,736	-	-	346,934	-
74 Income Before Tax		326,659,487	46,331,551	(26,144,539)	69,003,068	(20,718,581)
75						
76 State Income Taxes		14,830,341	2,103,452	(1,186,962)	3,132,739	(940,624)
77 Taxable Income		311,829,146	44,228,099	(24,957,577)	65,870,329	(19,777,957)
78						
79 Federal Income Taxes + Other		53,666,191	9,287,901	(5,241,091)	13,832,769	(4,153,371)
APPROXIMATE PRICE CHANGE		18,027,429	(47,873,811)	27,030,695	(71,598,295)	84,375,616

Pacificorp
Oregon General Rate Case Adjustment Summary
Twelve Months Ending December 31, 2021

	Exhibit PAC/1302		
	Tab 7	Tab 8	OR Allocated
	Tax Adjustments	Rate Base Adjustments	Results of Operations December 2021
1 Operating Revenues:			
2 General Business Revenues	-	-	1,308,884,715
3 Interdepartmental	-	-	-
4 Special Sales	-	-	73,285,143
5 Other Operating Revenues	-	4,630,292	50,008,283
6 Total Operating Revenues	-	4,630,292	1,432,178,141
7			
8 Operating Expenses:			
9 Steam Production	-	(6,582,064)	247,310,378
10 Nuclear Production	-	-	-
11 Hydro Production	-	-	11,814,928
12 Other Power Supply	-	4,042,177	257,424,578
13 Transmission	-	-	56,016,262
14 Distribution	-	-	69,726,150
15 Customer Accounting	-	-	30,202,104
16 Customer Service & Info	-	-	6,141,331
17 Sales	-	-	-
18 Administrative & General	-	(3,264,165)	41,472,852
19			
20 Total O&M Expenses	-	(5,804,053)	720,108,582
21			
22 Depreciation	-	24,764,195	316,560,184
23 Amortization	-	(1,795,238)	21,091,819
24 Taxes Other Than Income	8,707,023	-	86,353,112
25 Income Taxes - Federal	(58,244,494)	(19,734,923)	(10,587,018)
26 Income Taxes - State	(4,829,434)	(4,469,414)	8,640,100
27 Income Taxes - Def Net	8,245,699	18,214,115	(11,537,533)
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	546,879
30			
31 Total Operating Expenses:	(46,121,206)	11,174,683	1,131,176,126
32			
33 Operating Rev For Return:	46,121,206	(6,544,392)	301,002,015
34			
35 Rate Base:			
36 Electric Plant In Service	-	727,352,118	8,433,754,519
37 Plant Held for Future Use	-	(10,699,976)	-
38 Misc Deferred Debits	-	(118,340,307)	67,302,496
39 Elec Plant Acq Adj	-	(2,488,575)	1,749,820
40 Pensions	-	(676,399)	-
41 Prepayments	-	-	8,805,023
42 Fuel Stock	-	(3,388,408)	42,986,611
43 Material & Supplies	-	(1,723,272)	73,659,471
44 Working Capital	(513,876)	(403,824)	8,091,631
45 Weatherization Loans	-	-	(1,363)
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	(513,876)	589,631,356	8,636,348,208
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	-	(91,044,646)	(3,200,067,136)
52 Accum Prov For Amort	-	-	(190,276,927)
53 Accum Def Income Tax	502,844,924	22,205,926	(591,816,891)
54 Unamortized ITC	63,124	-	0
55 Customer Adv For Const	-	2,520,464	(13,802,322)
56 Customer Service Deposits	-	-	-
57 Misc Rate Base Deductions	(349,960,317)	18,687,478	(445,680,643)
58			
59 Total Rate Base Deductions	152,947,731	(47,630,778)	(4,441,643,918)
60			
61 Total Rate Base:	152,433,855	542,000,578	4,194,704,290
62			
63 Return on Rate Base	0.951%	-1.244%	7.176%
64			
65 Return on Equity	1.777%	-2.324%	9.265%
66			
67 TAX CALCULATION:			
68 Operating Revenue	(8,707,023)	(12,534,613)	287,517,564
69 Other Deductions			
70 Interest (AFUDC)	(5,862,773)	-	(18,867,154)
71 Interest	3,378,878	12,014,088	93,235,859
72 Schedule "M" Additions	(10,550,400)	20,469,088	397,826,658
73 Schedule "M" Deductions	89,601,661	94,365,623	420,664,954
74 Income Before Tax	(106,375,188)	(98,445,236)	190,310,563
75			
76 State Income Taxes	(4,829,434)	(4,469,414)	8,640,100
77 Taxable Income	(101,545,755)	(93,975,822)	181,670,463
78			
79 Federal Income Taxes + Other	(58,244,494)	(19,734,923)	(10,587,018)
APPROXIMATE PRICE CHANGE	(47,181,579)	66,002,590	28,782,645

Docket No. UE 374
Exhibit PAC/1302
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Oregon Results of Operations – December 2021

February 2020

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

(1)	Test Period 2020 Protocol Revenue Requirement	1,337,667,361	Page 1.1
(2)	Normalized General Business Revenues	1,308,884,715	Page 1.1
(3)	2020 Protocol Price Change*	**28,782,645**	Page 1.1

*Includes TAM and GRC

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

		(1) NPC-Related Results	(2) (3) - (1) Non-NPC Related Results	(3) Ref. Page 1.3 Total Adjusted Results	(4) Ref. Page 1.2 TAM NPC-Related Under Recovery	(5) Ref. Page 1.1 GRC Requested Non-NPC Related Price Change	(6) (3) + (4) + (5) Total Normalized Results with Price Change
1	Operating Revenues:						
2	General Business Revenues	341,185,758	967,698,957	1,308,884,715	(49,210,532)	77,993,178	1,337,667,361
3	Interdepartmental		-	-			-
4	Special Sales	73,285,143	-	73,285,143			73,285,143
5	Other Operating Revenues		50,008,283	50,008,283			50,008,283
6	Total Operating Revenues	414,470,901	1,017,707,240	1,432,178,141	(49,210,532)	77,993,178	1,460,960,786
7							
8	Operating Expenses:						
9	Steam Production	156,671,450	90,638,928	247,310,378			247,310,378
10	Nuclear Production		-	-			-
11	Hydro Production		11,814,928	11,814,928			11,814,928
12	Other Power Supply	237,044,768	20,379,809	257,424,578			257,424,578
13	Transmission	36,165,687	19,850,575	56,016,262			56,016,262
14	Distribution		69,726,150	69,726,150			69,726,150
15	Customer Accounting		30,202,104	30,202,104		110,860	30,312,965
16	Customer Service & Info		6,141,331	6,141,331			6,141,331
17	Sales		-	-			-
18	Administrative & General		41,472,852	41,472,852			41,472,852
19							
20	Total O&M Expenses	429,881,905	290,226,678	720,108,582	-	110,860	720,219,443
21							
22	Depreciation		316,560,184	316,560,184			316,560,184
23	Amortization		21,091,819	21,091,819			21,091,819
24	Taxes Other Than Income		86,353,112	86,353,112		828,595	87,181,707
25	Income Taxes - Federal	(51,822,679)	41,235,661	(10,587,018)	(9,865,039)	15,446,652	(5,005,405)
26	Income Taxes - State	(699,660)	9,339,759	8,640,100	(2,234,158)	3,498,239	9,904,180
27	Income Taxes - Def Net		(11,537,533)	(11,537,533)			(11,537,533)
28	Investment Tax Credit Adj.		-	-			-
29	Misc Revenue & Expense		546,879	546,879			546,879
30							
31	Total Operating Expenses:	377,359,566	753,816,560	1,131,176,126	(12,099,197)	19,884,346	1,138,961,275
32							
33	Operating Rev For Return:	37,111,335	263,890,680	301,002,015	(37,111,335)	58,108,832	321,999,512
34							
35	Rate Base:						
36	Electric Plant In Service		8,433,754,519	8,433,754,519			8,433,754,519
37	Plant Held for Future Use		-	-			-
38	Misc Deferred Debits		67,302,496	67,302,496			67,302,496
39	Elec Plant Acq Adj		1,749,820	1,749,820			1,749,820
40	Pension		-	-			-
41	Prepayments		8,805,023	8,805,023			8,805,023
42	Fuel Stock		42,986,611	42,986,611			42,986,611
43	Material & Supplies		73,659,471	73,659,471			73,659,471
44	Working Capital		8,091,631	8,091,631			8,091,631
45	Weatherization Loans		(1,363)	(1,363)			(1,363)
46	Misc Rate Base		-	-			-
47							
48	Total Electric Plant:	-	8,636,348,208	8,636,348,208			8,636,348,208
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec		(3,200,067,136)	(3,200,067,136)			(3,200,067,136)
52	Accum Prov For Amort		(190,276,927)	(190,276,927)			(190,276,927)
53	Accum Def Income Tax		(591,816,891)	(591,816,891)			(591,816,891)
54	Unamortized ITC		0	0			0
55	Customer Adv For Const		(13,802,322)	(13,802,322)			(13,802,322)
56	Customer Service Deposits		-	-			-
57	Misc Rate Base Deductions		(445,680,643)	(445,680,643)			(445,680,643)
58							
59	Total Rate Base Deductions	-	(4,441,643,918)	(4,441,643,918)			(4,441,643,918)
60							
61	Total Rate Base:	-	4,194,704,290	4,194,704,290			4,194,704,290
62							
63	Return on Rate Base			7.176%			7.676%
64							
65	Return on Equity			9.265%			10.200%

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

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	967,698,957	77,993,178	1,045,692,135
3	Interdepartmental	-		-
4	Special Sales	-		-
5	Other Operating Revenues	50,008,283		50,008,283
6	Total Operating Revenues	1,017,707,240	77,993,178	1,095,700,417
7				
8	Operating Expenses:			
9	Steam Production	90,638,928		90,638,928
10	Nuclear Production	-		-
11	Hydro Production	11,814,928		11,814,928
12	Other Power Supply	20,379,809		20,379,809
13	Transmission	19,850,575		19,850,575
14	Distribution	69,726,150		69,726,150
15	Customer Accounting	30,202,104	110,860	30,312,965
16	Customer Service & Info	6,141,331		6,141,331
17	Sales	-		-
18	Administrative & General	41,472,852		41,472,852
19				
20	Total O&M Expenses	290,226,678	110,860	290,337,538
21				
22	Depreciation	316,560,184		316,560,184
23	Amortization	21,091,819		21,091,819
24	Taxes Other Than Income	86,353,112	828,595	87,181,707
25	Income Taxes - Federal	41,235,661	15,446,652	56,682,313
26	Income Taxes - State	9,339,759	3,498,239	12,837,998
27	Income Taxes - Def Net	(11,537,533)		(11,537,533)
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	546,879		546,879
30				
31	Total Operating Expenses:	753,816,560	19,884,346	773,700,906
32				
33	Operating Rev For Return:	263,890,680	58,108,832	321,999,512
34				
35	Rate Base:			
36	Electric Plant In Service	8,433,754,519		8,433,754,519
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	67,302,496		67,302,496
39	Elec Plant Acq Adj	1,749,820		1,749,820
40	Pension	-		-
41	Prepayments	8,805,023		8,805,023
42	Fuel Stock	42,986,611		42,986,611
43	Material & Supplies	73,659,471		73,659,471
44	Working Capital	8,091,631		8,091,631
45	Weatherization Loans	(1,363)		(1,363)
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	8,636,348,208		8,636,348,208
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,200,067,136)		(3,200,067,136)
52	Accum Prov For Amort	(190,276,927)		(190,276,927)
53	Accum Def Income Tax	(591,816,891)		(591,816,891)
54	Unamortized ITC	0		0
55	Customer Adv For Const	(13,802,322)		(13,802,322)
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	(445,680,643)		(445,680,643)
58				
59	Total Rate Base Deductions	(4,441,643,918)		(4,441,643,918)
60				
61	Total Rate Base:	4,194,704,290		4,194,704,290
62				
63	Return on Rate Base	6.291%		7.676%
64				
65	Return on Equity	7.612%		10.200%
66				
67	TAX CALCULATION:			
68	Operating Revenue	302,928,567	77,053,723	379,982,290
69	Other Deductions			
70	Interest (AFUDC)	(18,867,154)	-	(18,867,154)
71	Interest	93,235,859	-	93,235,859
72	Schedule "M" Additions	397,826,658	-	397,826,658
73	Schedule "M" Deductions	420,664,954	-	420,664,954
74	Income Before Tax	205,721,566	77,053,723	282,775,289
75				
76	State Income Taxes	9,339,759	3,498,239	12,837,998
77	Taxable Income	196,381,807	73,555,484	269,937,291
78				
79	Federal Income Taxes + Other	41,235,661	15,446,652	56,682,313

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

TRANSITION ADJUSTMENT MECHANISM RESULTS

		(1) Total Adjusted Results	(2) **TAM** Price Change	(3) (1) + (2) Total Normalized Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	341,185,758	(49,210,532)	291,975,226
3	Interdepartmental	-		-
4	Special Sales	73,285,143		73,285,143
5	Other Operating Revenues	-		-
6	Total Operating Revenues	414,470,901	(49,210,532)	365,260,369
7				
8	Operating Expenses:			
9	Steam Production	156,671,450		156,671,450
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	237,044,768		237,044,768
13	Transmission	36,165,687		36,165,687
14	Distribution	-		-
15	Customer Accounting	-	-	-
16	Customer Service & Info	-		-
17	Sales	-		-
18	Administrative & General	-		-
19				
20	Total O&M Expenses	429,881,905	-	429,881,905
21				
22	Depreciation	-		-
23	Amortization	-		-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	(51,822,679)	(9,865,039)	(61,687,718)
26	Income Taxes - State	(699,660)	(2,234,158)	(2,933,818)
27	Income Taxes - Def Net	-		-
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	-		-
30				
31	Total Operating Expenses:	377,359,566	(12,099,197)	365,260,369
32				
33	Operating Rev For Return:	37,111,335	(37,111,335)	-
34				
35	Rate Base:			
36	Electric Plant In Service	-		-
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	-		-
39	Elec Plant Acq Adj	-		-
40	Pension	-		-
41	Prepayments	-		-
42	Fuel Stock	-		-
43	Material & Supplies	-		-
44	Working Capital	-		-
45	Weatherization Loans	-		-
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	-		-
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-		-
52	Accum Prov For Amort	-		-
53	Accum Def Income Tax	-		-
54	Unamortized ITC	-		-
55	Customer Adv For Const	-		-
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	-		-
58				
59	Total Rate Base Deductions	-		-
60				
61	Total Rate Base:	-		-
62				
63	Return on Rate Base	N/A		N/A
64				
65	Return on Equity	N/A		N/A
66				
67	TAX CALCULATION:			
68	Operating Revenue	(15,411,004)	(49,210,532)	(64,621,536)
69	Other Deductions			
70	Interest (AFUDC)	-	-	-
71	Interest	-	-	-
72	Schedule "M" Additions	-	-	-
73	Schedule "M" Deductions	-	-	-
74	Income Before Tax	(15,411,004)	(49,210,532)	(64,621,536)
75				
76	State Income Taxes	(699,660)	(2,234,158)	(2,933,818)
77	Taxable Income	(14,711,344)	(46,976,374)	(61,687,718)
78				
79	Federal Income Taxes + Other	(51,822,679)	(9,865,039)	(61,687,718)

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL Twelve Months
Ending December 31, 2021

COMBINED TAM AND GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,308,884,715	28,782,645	1,337,667,361
3	Interdepartmental	-		
4	Special Sales	73,285,143		
5	Other Operating Revenues	50,008,283		
6	Total Operating Revenues	1,432,178,141		
7				
8	Operating Expenses:			
9	Steam Production	247,310,378		
10	Nuclear Production	-		
11	Hydro Production	11,814,928		
12	Other Power Supply	257,424,578		
13	Transmission	56,016,262		
14	Distribution	69,726,150		
15	Customer Accounting	30,202,104	110,860	30,312,965
16	Customer Service & Info	6,141,331		
17	Sales	-		
18	Administrative & General	41,472,852		
19				
20	Total O&M Expenses	720,108,582		
21				
22	Depreciation	316,560,184		
23	Amortization	21,091,819		
24	Taxes Other Than Income	86,353,112	828,595	87,181,707
25	Income Taxes - Federal	(10,587,018)	5,581,613	(5,005,405)
26	Income Taxes - State	8,640,100	1,264,081	9,904,180
27	Income Taxes - Def Net	(11,537,533)		
28	Investment Tax Credit Adj.	-		
29	Misc Revenue & Expense	546,879		
30				
31	Total Operating Expenses:	1,131,176,126	7,785,149	1,138,961,275
32				
33	Operating Rev For Return:	301,002,015	20,997,497	321,999,512
34				
35	Rate Base:			
36	Electric Plant In Service	8,433,754,519		
37	Plant Held for Future Use	-		
38	Misc Deferred Debits	67,302,496		
39	Elec Plant Acq Adj	1,749,820		
40	Pensions	-		
41	Prepayments	8,805,023		
42	Fuel Stock	42,986,611		
43	Material & Supplies	73,659,471		
44	Working Capital	8,091,631		
45	Weatherization Loans	(1,363)		
46	Misc Rate Base	-		
47				
48	Total Electric Plant:	8,636,348,208	-	8,636,348,208
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,200,067,136)		
52	Accum Prov For Amort	(190,276,927)		
53	Accum Def Income Tax	(591,816,891)		
54	Unamortized ITC	0		
55	Customer Adv For Const	(13,802,322)		
56	Customer Service Deposits	-		
57	Misc Rate Base Deductions	(445,680,643)		
58				
59	Total Rate Base Deductions	(4,441,643,918)	-	(4,441,643,918)
60				
61	Total Rate Base:	4,194,704,290	-	4,194,704,290
62				
63	Return on Rate Base	7.176%		7.676%
64				
65	Return on Equity	9.265%		10.200%
66				
67	TAX CALCULATION:			
68	Operating Revenue	287,517,564	27,843,190	315,360,754
69	Other Deductions			
70	Interest (AFUDC)	(18,867,154)	-	(18,867,154)
71	Interest	93,235,859	-	93,235,859
72	Schedule "M" Additions	397,826,658	-	397,826,658
73	Schedule "M" Deductions	420,664,954	-	420,664,954
74	Income Before Tax	190,310,563	27,843,190	218,153,753
75				
76	State Income Taxes	8,640,100	1,264,081	9,904,180
77	Taxable Income	181,670,463	26,579,110	208,249,573
78				
79	Federal Income Taxes + Other	(10,587,018)	5,581,613	(5,005,405)

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

Net Rate Base	$	4,194,704,290	Ref. Page 1.1
Return on Rate Base Requested		7.68%	Ref. Page 2.1
Revenues Required to Earn Requested Return		321,999,512	
Less Current Operating Revenues		(301,002,015)	
Increase to Current Revenues		20,997,497	
Net to Gross Bump-up		137.08%	
Price Change Required for Requested Return	$	28,782,645	
Requested Price Change	$	28,782,645	
Uncollectible Percent		0.385%	Ref. Page 1.6
Increased Uncollectible Expense	$	110,860	
Requested Price Change	$	28,782,645	
Franchise Tax		2.350%	Ref. Page 1.6
Revenue Tax		0.000%	Ref. Page 1.6
Resource Supplier Tax		0.129%	Ref. Page 1.6
PUC Fees Based on General Business Revenues		0.400%	Ref. Page 1.6
Increase Taxes Other Than Income	$	828,595	
Requested Price Change	$	28,782,645	
Uncollectible Expense		(110,860)	
Taxes Other Than Income		(828,595)	
Income Before Taxes	$	27,843,190	
State Effective Tax Rate		4.54%	Ref. Page 2.1
State Income Taxes	$	1,264,081	
Taxable Income	$	26,579,110	
Federal Income Tax Rate		21.00%	Ref. Page 2.1
Federal Income Taxes	$	5,581,613	
Operating Income		100.000%	
Net Operating Income		72.952%	Ref. Page 1.6
Net to Gross Bump-Up		137.08%	

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2021

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.385%	See Note (1) Below
Taxes Other - Franchise Tax	2.350%	
Taxes Other - Revenue Tax	0.000%	
Taxes Other - Resource Supplier	0.129%	
PUC Fees Based on General Business Revenues	0.400%	
Sub-Total	96.736%	
State Income Tax @ 4.54%	4.392%	
Sub-Total	92.344%	
Federal Income Tax @ 21.00%	19.392%	
Net Operating Income	72.952%	

(1) Uncollectible Accounts =	5,041,346	Pg 2.11, OREGON Situs from Account 904
	1,308,884,715	Pg. 2.2, General Business Revenues

Pacificorp
Oregon General Rate Case Adjustment Summary
Twelve Months Ending December 31, 2021

	TOTAL COMPANY UNADJUSTED RESULTS JUNE 2019	OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2019	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	4,738,801,365	1,262,527,098	44,630,291	1,727,327	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	243,934,081	59,812,893	-	-	13,472,250	-
5 Other Operating Revenues	177,063,148	45,048,206	1,703,647	(1,373,862)	-	-
6 Total Operating Revenues	5,159,798,594	1,367,388,196	46,333,938	353,465	13,472,250	-
7						
8 Operating Expenses:						
9 Steam Production	1,099,966,583	280,291,135	-	4,699,824	(35,024,379)	3,925,862
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	42,311,811	11,010,647	-	732,670	-	71,612
12 Other Power Supply	1,023,059,582	270,418,727	-	3,155,329	(20,239,216)	47,561
13 Transmission	212,793,850	55,389,954	-	1,215,813	(627,267)	37,762
14 Distribution	200,837,597	60,083,160	-	9,470,192	-	172,798
15 Customer Accounting	82,050,225	27,728,842	-	2,406,815	-	66,448
16 Customer Service & Info	99,292,578	5,678,204	-	450,160	-	12,967
17 Sales	-	-	-	-	-	-
18 Administrative & General	144,701,044	42,342,058	-	2,337,441	-	57,518
19						
20 Total O&M Expenses	2,905,013,270	752,942,727	-	24,468,244	(55,890,862)	4,392,527
21						
22 Depreciation	724,543,948	202,457,473	-	-	-	89,338,517
23 Amortization	53,602,343	14,431,373	-	-	45,829	8,409,854
24 Taxes Other Than Income	199,541,666	76,539,794	-	1,106,296	-	-
25 Income Taxes - Federal	205,103,291	53,666,191	9,287,901	(5,241,091)	13,832,769	(4,153,371)
26 Income Taxes - State	56,734,959	14,830,341	2,103,452	(1,186,962)	3,132,739	(940,624)
27 Income Taxes - Def Net	(183,345,084)	(19,234,974)	-	-	74,031	(18,836,403)
28 Investment Tax Credit Adj.	(2,943,987)	-	-	-	-	-
29 Misc Revenue & Expense	(3,327,067)	(372,574)	-	919,453	-	-
30						
31 Total Operating Expenses:	3,954,923,338	1,095,260,350	11,391,353	20,065,939	(38,805,494)	78,210,500
32						
33 Operating Rev For Return:	1,204,875,256	272,127,846	34,942,585	(19,712,474)	52,277,744	(78,210,500)
34						
35 Rate Base:						
36 Electric Plant In Service	28,210,093,332	7,705,361,496	-	-	1,040,905	-
37 Plant Held for Future Use	26,421,395	10,699,976	-	-	-	-
38 Misc Deferred Debits	852,539,521	185,642,803	-	-	-	-
39 Elec Plant Acq Adj	26,756,854	4,238,395	-	-	-	-
40 Pensions	2,485,363	676,399	-	-	-	-
41 Prepayments	46,540,395	8,805,023	-	-	-	-
42 Fuel Stock	184,750,079	46,375,019	-	-	-	-
43 Material & Supplies	249,437,716	75,382,743	-	-	-	-
44 Working Capital	49,534,022	16,235,238	107,671	180,973	(367,923)	(7,146,628)
45 Weatherization Loans	(8,425,958)	(1,363)	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	29,640,132,719	8,053,415,730	107,671	180,973	672,983	(7,146,628)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(10,032,916,685)	(2,903,746,581)	-	-	-	(205,275,908)
52 Accum Prov For Amort	(618,766,978)	(180,648,350)	-	-	-	(9,628,577)
53 Accum Def Income Tax	(4,311,827,079)	(1,121,847,609)	-	-	(81,517)	5,061,385
54 Unamortized ITC	(297,497)	(63,124)	-	-	-	-
55 Customer Adv For Const	(61,656,010)	(16,322,786)	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(655,284,072)	(114,407,804)	-	-	-	-
58						
59 Total Rate Base Deductions	(15,680,748,321)	(4,337,036,255)	-	-	(81,517)	(209,843,100)
60						
61 Total Rate Base:	13,737,172,111	3,716,379,475	107,671	180,973	591,466	(216,989,729)
62						
63 Return on Rate Base		7.322%	0.940%	-0.531%	1.405%	-1.668%
64						
65 Return on Equity		9.539%	1.756%	-0.992%	2.625%	-3.117%
66						
67 TAX CALCULATION:						
68 Operating Revenue		321,389,404	46,333,938	(26,140,528)	69,317,284	(102,140,898)
69 Other Deductions						
70 Interest (AFUDC)		(13,004,380)	-	-	-	-
71 Interest		82,633,220	2,387	4,011	13,111	(4,809,836)
72 Schedule "M" Additions		311,249,659	-	-	45,829	76,612,482
73 Schedule "M" Deductions		236,350,736	-	-	346,934	-
74 Income Before Tax		326,659,487	46,331,551	(26,144,539)	69,003,068	(20,718,581)
75						
76 State Income Taxes		14,830,341	2,103,452	(1,186,962)	3,132,739	(940,624)
77 Taxable Income		311,829,146	44,228,099	(24,957,577)	65,870,329	(19,777,957)
78						
79 Federal Income Taxes + Other		53,666,191	9,287,901	(5,241,091)	13,832,769	(4,153,371)
APPROXIMATE PRICE CHANGE		18,027,429	(47,873,811)	27,030,695	(71,598,295)	84,375,616

Pacificorp
Oregon General Rate Case Adjustment
Summary
Twelve Months Ending December 31, 2021

		Tab 7	Tab 8	OR Allocated
		Tax Adjustments	Rate Base Adjustments	Results of Operations December 2021
1	Operating Revenues:			
2	General Business Revenues	-	-	1,308,884,715
3	Interdepartmental	-	-	-
4	Special Sales	-	-	73,285,143
5	Other Operating Revenues	-	4,630,292	50,008,283
6	Total Operating Revenues	-	4,630,292	1,432,178,141
7				
8	Operating Expenses:			
9	Steam Production	-	(6,582,064)	247,310,378
10	Nuclear Production	-	-	-
11	Hydro Production	-	-	11,814,928
12	Other Power Supply	-	4,042,177	257,424,578
13	Transmission	-	-	56,016,262
14	Distribution	-	-	69,726,150
15	Customer Accounting	-	-	30,202,104
16	Customer Service & Info	-	-	6,141,331
17	Sales	-	-	-
18	Administrative & General	-	(3,264,165)	41,472,852
19				
20	Total O&M Expenses	-	(5,804,053)	720,108,582
21				
22	Depreciation	-	24,764,195	316,560,184
23	Amortization	-	(1,795,238)	21,091,819
24	Taxes Other Than Income	8,707,023	-	86,353,112
25	Income Taxes - Federal	(58,244,494)	(19,734,923)	(10,587,018)
26	Income Taxes - State	(4,829,434)	(4,469,414)	8,640,100
27	Income Taxes - Def Net	8,245,699	18,214,115	(11,537,533)
28	Investment Tax Credit Adj.	-	-	-
29	Misc Revenue & Expense	-	-	546,879
30				
31	Total Operating Expenses:	(46,121,206)	11,174,683	1,131,176,126
32				
33	Operating Rev For Return:	46,121,206	(6,544,392)	301,002,015
34				
35	Rate Base:			
36	Electric Plant In Service	-	727,352,118	8,433,754,519
37	Plant Held for Future Use	-	(10,699,976)	-
38	Misc Deferred Debits	-	(118,340,307)	67,302,496
39	Elec Plant Acq Adj	-	(2,488,575)	1,749,820
40	Pensions	-	(676,399)	-
41	Prepayments	-	-	8,805,023
42	Fuel Stock	-	(3,388,408)	42,986,611
43	Material & Supplies	-	(1,723,272)	73,659,471
44	Working Capital	(513,876)	(403,824)	8,091,631
45	Weatherization Loans	-	-	(1,363)
46	Misc Rate Base	-	-	-
47				
48	Total Electric Plant:	(513,876)	589,631,356	8,636,348,208
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-	(91,044,646)	(3,200,067,136)
52	Accum Prov For Amort	-	-	(190,276,927)
53	Accum Def Income Tax	502,844,924	22,205,926	(591,816,891)
54	Unamortized ITC	63,124	-	0
55	Customer Adv For Const	-	2,520,464	(13,802,322)
56	Customer Service Deposits	-	-	-
57	Misc Rate Base Deductions	(349,960,317)	18,687,478	(445,680,643)
58				
59	Total Rate Base Deductions	152,947,731	(47,630,778)	(4,441,643,918)
60				
61	Total Rate Base:	152,433,855	542,000,578	4,194,704,290
62				
63	Return on Rate Base	0.951%	-1.244%	7.176%
64				
65	Return on Equity	1.777%	-2.324%	9.265%
66				
67	TAX CALCULATION:			
68	Operating Revenue	(8,707,023)	(12,534,613)	287,517,564
69	Other Deductions			
70	Interest (AFUDC)	(5,862,773)	-	(18,867,154)
71	Interest	3,378,878	12,014,088	93,235,859
72	Schedule "M" Additions	(10,550,400)	20,469,088	397,826,658
73	Schedule "M" Deductions	89,601,661	94,365,623	420,664,954
74	Income Before Tax	(106,375,188)	(98,445,236)	190,310,563
75				
76	State Income Taxes	(4,829,434)	(4,469,414)	8,640,100
77	Taxable Income	(101,545,755)	(93,975,822)	181,670,463
78				
79	Federal Income Taxes + Other	(58,244,494)	(19,734,923)	(10,587,018)
	APPROXIMATE PRICE CHANGE	(47,181,579)	66,002,590	28,782,645

PacifiCorp
RESULTS OF OPERATIONS

USER SPECIFIC INFORMATION

STATE:	OREGON
PERIOD:	TWELVE MONTHS ENDING DECEMBER 31, 2021
FILE:	OR JAM Dec 2021 GRC
PREPARED BY:	Revenue Requirement Department
DATE:	2/6/2020
TIME:	10:56:18 AM
TYPE OF RATE BASE:	Year End
ALLOCATION METHOD:	**2020 PROTOCOL**
FERC JURISDICTION:	Separate Jurisdiction
8 OR 12 CP:	12 Coincident Peaks
DEMAND %	75% Demand
ENERGY %	25% Energy

TAX INFORMATION

TAX RATE ASSUMPTIONS:	TAX RATE
FEDERAL RATE	21.00%
STATE EFFECTIVE RATE	4.54%
TAX GROSS UP FACTOR	1.371
FEDERAL/STATE COMBINED RATE	24.587%

CAPITAL STRUCTURE INFORMATION

	CAPITAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
DEBT	46.47%	4.77%	2.22%
PREFERRED	0.01%	6.75%	0.00%
COMMON	53.52%	10.20%	5.46%
	100.00%		7.68%

OTHER INFORMATION

For information and support regarding capital structure and cost of debt, see testimony of Ms. Nikki L. Kobliha.
For information and support regarding return on common equity, see testimony of Ms. Ann E. Bulkley.

2020 PROTOCOL
Year End

RESULTS OF OPERATIONS SUMMARY

	Description of Account Summary:	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
1	Operating Revenues					
2	General Business Revenues	2.2	4,738,801,365	1,262,527,098	4,785,158,983	1,308,884,715
3	Interdepartmental	2.2	0	0	0	0
4	Special Sales	2.2	243,934,081	59,812,893	295,705,384	73,285,143
5	Other Operating Revenues	2.3	177,063,148	45,048,206	186,866,366	50,008,283
6	Total Operating Revenues	2.3	5,159,798,594	1,367,388,196	5,267,730,734	1,432,178,141
7						
8	Operating Expenses:					
9	Steam Production	2.5	1,099,966,583	280,291,135	974,368,847	247,310,378
10	Nuclear Production	2.5	0	0	0	0
11	Hydro Production	2.6	42,311,811	11,010,647	45,402,509	11,814,928
12	Other Power Supply	2.7, .8	1,013,398,680	270,418,727	959,258,556	257,424,578
13	Transmission	2.9	212,793,850	55,389,954	215,355,152	56,016,262
14	Distribution	2.10	200,837,597	60,083,160	222,027,327	69,726,150
15	Customer Accounting	2.11	82,050,225	27,728,842	89,120,892	30,202,104
16	Customer Service & Infor	2.12	99,292,578	5,678,204	103,900,457	6,141,331
17	Sales	2.12	0	0	0	0
18	Administrative & General	2.13	144,701,044	42,342,058	144,034,397	41,472,852
19						
20	Total O & M Expenses	2.13	2,895,352,368	752,942,727	2,753,468,138	720,108,582
21						
22	Depreciation	2.14	724,543,948	202,457,473	1,184,472,345	316,560,184
23	Amortization	2.15	53,602,343	14,431,373	84,071,945	21,091,819
24	Taxes Other Than Income	2.15	199,541,666	76,539,794	232,642,537	86,353,112
25	Income Taxes - Federal	2.18	207,219,461	53,666,191	(57,431,087)	(10,587,018)
26	Income Taxes - State	2.18	57,214,213	14,830,341	29,409,617	8,640,100
27	Income Taxes - Def Net	2.16	(183,345,084)	(19,234,974)	(73,578,240)	(11,537,533)
28	Investment Tax Credit Adj.	2.15	(2,943,987)	0	(2,943,987)	0
29	Misc Revenue & Expense	2.3	(3,327,067)	(372,574)	(80,922)	546,879
30						
31	Total Operating Expenses	2.18	3,947,857,860	1,095,260,350	4,150,030,346	1,131,176,126
32						
33	Operating Revenue for Return		1,211,940,734	272,127,846	1,117,700,388	301,002,015
34						
35	Rate Base:					
36	Electric Plant in Service	2.26	28,210,093,332	7,705,361,496	30,989,004,997	8,433,754,519
37	Plant Held for Future Use	2.26	26,421,395	10,699,976	0	0
38	Misc Deferred Debits	2.28	852,539,521	185,642,803	410,101,660	67,302,496
39	Elec Plant Acq Adj	2.26,.27	26,756,854	4,238,395	17,193,735	1,749,820
40	Pensions	2.27	2,485,363	676,399	0	0
41	Prepayments	2.28	46,540,395	8,805,023	46,540,395	8,805,023
42	Fuel Stock	2.27	184,750,079	46,375,019	171,251,246	42,986,611
43	Material & Supplies	2.28	249,437,716	75,382,743	242,815,511	73,659,471
44	Working Capital	2.28	49,571,851	16,235,238	17,583,931	8,091,631
45	Weatherization Loans	2.27	(8,425,958)	(1,363)	(8,425,958)	(1,363)
46	Miscellaneous Rate Base	2.29	0	0	0	0
47						
48	Total Electric Plant		29,640,170,548	8,053,415,730	31,886,065,518	8,636,348,208
49						
50	Rate Base Deductions:					
51	Accum Prov For Depr	2.32	(10,032,916,685)	(2,903,746,581)	(11,160,312,636)	(3,200,067,136)
52	Accum Prov For Amort	2.33	(618,766,978)	(180,648,350)	(646,430,570)	(190,276,927)
53	Accum Def Income Taxes	2.30	(4,311,827,079)	(1,121,847,609)	(2,760,089,212)	(591,816,891)
54	Unamortized ITC	2.30	(297,497)	(63,124)	1	0
55	Customer Adv for Const	2.29	(61,656,010)	(16,322,786)	(61,656,010)	(13,802,322)
56	Customer Service Deposits	2.29	0	0	0	0
57	Misc. Rate Base Deductions	2.29	(655,284,072)	(114,407,804)	(864,882,312)	(445,680,643)
58						
59	Total Rate Base Deductions		(15,680,748,321)	(4,337,036,255)	(15,493,370,740)	(4,441,643,918)
60						
61	Total Rate Base		13,959,422,227	3,716,379,475	16,392,694,778	4,194,704,290
62						
63	Return on Rate Base		8.682%	7.322%	6.818%	7.176%
64						
65	Return on Equity		12.079%	9.539%	8.597%	9.265%
66	Net Power Costs		1,678,049,950	426,089,987	1,401,677,191	356,596,762
67	100 Basis Points in Equity:		74,710,828	19,890,063	87,733,702	22,450,057
68	Revenue Requirement Impact		99,068,372	26,374,707	116,337,020	29,769,321
69	Rate Base Decrease		(810,569,093)	(253,131,809)	(1,193,090,371)	(291,144,686)

	2020 PROTOCOL					JUNE 2019		DECEMBER 2021	
	Year End					UNADJUSTED RESULTS		NORMALIZED RESULTS	
	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
70	Sales to Ultimate Customers								
71	440	Residential Sales							
72			0	S		1,808,805,075	629,272,437	1,825,391,907	645,859,269
73									
74					B1	1,808,805,075	629,272,437	1,825,391,907	645,859,269
75									
76	442	Commercial & Industrial Sales							
77			0	S		2,911,591,589	627,285,353	2,943,266,555	658,960,319
78			P	SE		-	-	-	-
79			PT	SG		-	-	-	-
80									
81									
82					B1	2,911,591,589	627,285,353	2,943,266,555	658,960,319
83									
84	444	Public Street & Highway Lighting							
85			0	S		18,404,701	5,969,307	16,500,521	4,065,127
86			0	SO		-	-	-	-
87					B1	18,404,701	5,969,307	16,500,521	4,065,127
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	**Total Sales to Ultimate Customers**				**B1**	**4,738,801,365**	**1,262,527,098**	**4,785,158,983**	**1,308,884,715**
100									
101									
102									
103	447	Sales for Resale-Non NPC							
104			P	S		14,084,596	-	14,084,596	-
105					B1	14,084,596	-	14,084,596	-
106									
107	447NPC	Sales for Resale-NPC							
108			P	SG		229,850,101	59,813,047	281,620,789	73,285,143
109			P	SE		(616)	(155)	-	-
110			P	SG		-	-	-	-
111					B1	229,849,485	59,812,893	281,620,789	73,285,143
112									
113		Total Sales for Resale			B1	243,934,081	59,812,893	295,705,384	73,285,143
114									
115	449	Provision for Rate Refund							
116			P	S		-	-	-	-
117			P	SG		-	-	-	-
118									
119									
120					B1	-	-	-	-
121									
122	**Total Sales from Electricity**				**B1**	**4,982,735,447**	**1,322,339,990**	**5,080,864,368**	**1,382,169,858**
123	450	Forfeited Discounts & Interest							
124			CUST	S		9,589,380	4,242,722	9,589,380	4,242,722
125			CUST	SO		-	-	-	-
126					B1	9,589,380	4,242,722	9,589,380	4,242,722
127									
128	451	Misc Electric Revenue							
129			CUST	S		7,215,463	2,461,735	5,841,602	1,087,873
130			GP	SG		-	-	-	-
131			GP	SO		34,932	9,507	34,932	9,507
132					B1	7,250,396	2,471,242	5,876,534	1,097,380
133									
134	453	Water Sales							
135			P	SG		58,210	15,148	58,210	15,148
136					B1	58,210	15,148	58,210	15,148
137									
138	454	Rent of Electric Property							
139			DPW	S		9,513,442	3,723,611	9,513,442	3,723,611
140			T	SG		5,900,441	1,535,450	5,900,441	1,535,450
141			T	SG		-	-	-	-
142			GP	SO		1,699,946	462,646	1,699,946	462,646
143					B1	17,113,829	5,721,707	17,113,829	5,721,707

Line	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
144									
145									
146									
147	456	Other Electric Revenue							
148			DMSC	S		1,952,244	(4,012,252)	6,582,536	618,040
149			CUST	CN		-	-	-	-
150			OTHSE	SE		17,028,845	4,274,493	17,028,845	4,274,493
151			OTHSO	SO		4,091,872	1,113,616	4,091,872	1,113,616
152			OTHSGR	SG		119,978,372	31,221,531	126,525,161	32,925,178
153									
154									
155					B1	143,051,333	32,597,388	154,228,414	38,931,326
156									
157	**Total Other Electric Revenues**				**B1**	**177,063,148**	**45,048,206**	**186,866,366**	**50,008,283**
158									
159	**Total Electric Operating Revenues**				**B1**	**5,159,798,594**	**1,367,388,196**	**5,267,730,734**	**1,432,178,141**
160									
161	Summary of Revenues by Factor								
162		S				4,781,156,490	1,268,942,913	4,830,770,538	1,318,556,961
163		CN				-	-	-	-
164		SE				17,028,229	4,274,339	17,028,845	4,274,493
165		SO				5,826,750	1,585,768	5,826,750	1,585,768
166		SG				355,787,125	92,585,176	414,104,601	107,760,919
167		DGP				-	-	-	-
168									
169	Total Electric Operating Revenues					5,159,798,594	1,367,388,196	5,267,730,734	1,432,178,141
170	Miscellaneous Revenues								
171	41160	Gain on Sale of Utility Plant - CR							
172			DPW	S		-	-	-	-
173			T	SG		-	-	-	-
174			G	SO		-	-	-	-
175			T	SG		-	-	-	-
176			P	SG		-	-	-	-
177					B1	-	-	-	-
178									
179	41170	Loss on Sale of Utility Plant							
180			DPW	S		-	-	-	-
181			T	SG		-	-	-	-
182					B1	-	-	-	-
183									
184	4118	Gain from Emission Allowances							
185			P	S		-	-	-	-
186			P	SE		(173)	(44)	(173)	(44)
187					B1	(173)	(44)	(173)	(44)
188									
189	41181	Gain from Disposition of NOX Credits							
190			P	SE		-	-	-	-
191					B1	-	-	-	-
192									
193	4194	Impact Housing Interest Income							
194			P	SG		-	-	-	-
195					B1	-	-	-	-
196									
197	421	(Gain) / Loss on Sale of Utility Plant							
198			DPW	S		734,943	731,594	629,490	731,675
199			T	SG		26,718	6,953	26,718	6,953
200			T	SG		(137,165)	(35,694)	(137,165)	(35,694)
201			P	CN		-	-	-	-
202			PTD	SO		(3,951,390)	(1,075,383)	5,942	1,617
203			P	SG		-	-	(605,734)	(157,628)
204					B1	(3,326,894)	(372,531)	(80,749)	546,923
205									
206	**Total Miscellaneous Revenues**				**B1**	**(3,327,067)**	**(372,574)**	**(80,922)**	**546,879**
207	Miscellaneous Expenses								
208	4311	Interest on Customer Deposits							
209			CUST	S		-	-	-	-
210						-	-	-	-
211	**Total Miscellaneous Expenses**				B1	**-**	**-**	**-**	**-**
212									
213	**Net Misc Revenue and Expense**				**B1**	**(3,327,067)**	**(372,574)**	**(80,922)**	**546,879**
214									

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
215	500	Operation Supervision & Engineering							
216			P	SG		15,596,765	4,058,689	15,596,765	4,058,689
217			P	SG		2,462,779	640,880	2,462,779	640,880
218			P	SG		-	-	6,796,872	1,768,725
219					B2	18,059,545	4,699,569	24,856,417	6,468,294
220									
221	501	Fuel Related-Non NPC							
222			P	S		1,746,531	1,881,937	(140,947)	(5,541)
223			P	SE		23,055,537	5,787,283	54,487,780	13,677,243
224			P	SE		-	-	-	-
225			P	SE		-	-	-	-
226			P	SE		2,819,582	707,757	2,819,582	707,757
227					B2	27,621,649	8,376,977	57,166,414	14,379,460
228									
229	501NPC	Fuel Related-NPC							
230			P	S		398,108	-	-	-
231			P	SE		714,777,401	179,419,763	575,297,285	144,408,179
232			P	SE		-	-	-	-
233			P	SE		-	-	-	-
234			P	SE		44,335,052	11,128,758	44,335,052	11,128,758
235					B2	759,510,561	190,548,521	619,632,338	~~155,536,937~~
236									
237		Total Fuel Related			B2	787,132,210	198,925,498	676,798,752	169,916,396
238									
239	502	Steam Expenses							
240			P	SG		74,510,141	19,389,500	74,510,141	19,389,500
241			P	SG		7,737,962	2,013,621	7,737,962	2,013,621
242			P	SG		-	-	2,583,449	672,281
243					B2	82,248,103	21,403,122	84,831,552	22,075,403
244									
245	503	Steam From Other Sources-Non-NPC							
246			P	SE		-	-	(4,568)	(1,147)
247					B2	-	-	(4,568)	(1,147)
248									
249	503NPC	Steam From Other Sources-NPC							
250			P	SE		4,570,678	1,147,308	4,519,705	1,134,513
251					B2	4,570,678	1,147,308	4,519,705	1,134,513
252									
253	505	Electric Expenses							
254			P	SG		1,268,962	330,217	1,268,962	330,217
255			P	SG		298,020	77,553	298,020	77,553
256			P	SG		-	-	64,019	16,659
257					B2	1,566,982	407,770	1,631,001	424,430
258									
259	506	Misc. Steam Expense							
260			P	SG		27,210,000	7,080,758	27,210,000	7,080,758
261			P	SG		-	-	(33,187,250)	(8,636,196)
262			P	SG		2,037,857	530,304	2,037,857	530,304
263					B2	29,247,857	7,611,062	(3,939,393)	(1,025,134)
264									
265	507	Rents							
266			P	SG		515,835	134,234	515,835	134,234
267			P	SG		-	-	21,107	5,493
268			P	SG		-	-	-	-
269					B2	515,835	134,234	536,943	139,727
270									
271	510	Maint Supervision & Engineering							
272			P	SG		5,371,531	1,397,814	5,371,531	1,397,814
273			P	SG		2,718,835	707,512	2,718,835	707,512
274			P	SG		-	-	(1,443,755)	(375,703)
275					B2	8,090,366	2,105,326	6,646,611	1,729,623
276									
277									
278									
279	511	Maintenance of Structures							
280			P	SG		23,079,914	6,006,001	23,079,914	6,006,001
281			P	SG		3,709,903	965,415	3,709,903	965,415
282			P	SG		-	-	623,052	162,135
283					B2	26,789,817	6,971,416	27,412,870	7,133,550
284									
285	512	Maintenance of Boiler Plant							
286			P	SG		89,358,403	23,253,409	89,358,403	23,253,409
287			P	SG		6,140,690	1,597,969	6,140,690	1,597,969
288			P	SG		-	-	8,252,282	2,147,461
289					B2	95,499,093	24,851,378	103,751,375	26,998,839
290									
291	513	Maintenance of Electric Plant							
292			P	SG		34,988,575	9,104,948	34,988,575	9,104,948
293			P	SG		891,759	232,059	891,759	232,059
294			P	SG		-	-	809,990	210,781
295					B2	35,880,333	9,337,007	36,690,323	9,547,788

2020 PROTOCOL
Year End

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
296									
297	514	Maintenance of Misc. Steam Plant							
298			P	SG		8,781,068	2,285,065	8,781,068	2,285,065
299			P	SG		1,584,696	412,380	1,584,696	412,380
300			P	SG		-	-	271,496	70,650
301					B2	10,365,764	2,697,445	10,637,260	2,768,095
302									
303	**Total Steam Power Generation**				**B2**	**1,099,966,583**	**280,291,135**	**974,368,847**	**247,310,378**
304	517	Operation Super & Engineering							
305			P	SG		-	-	-	-
306					B2	-	-	-	-
307									
308	518	Nuclear Fuel Expense							
309			P	SE		-	-	-	-
310									
311					B2	-	-	-	-
312									
313	519	Coolants and Water							
314			P	SG		-	-	-	-
315					B2	-	-	-	-
316									
317	520	Steam Expenses							
318			P	SG		-	-	-	-
319					B2	-	-	-	-
320									
321									
322									
323	523	Electric Expenses							
324			P	SG		-	-	-	-
325					B2	-	-	-	-
326									
327	524	Misc. Nuclear Expenses							
328			P	SG		-	-	-	-
329					B2	-	-	-	-
330									
331	528	Maintenance Super & Engineering							
332			P	SG		-	-	-	-
333					B2	-	-	-	-
334									
335	529	Maintenance of Structures							
336			P	SG		-	-	-	-
337					B2	-	-	-	-
338									
339	530	Maintenance of Reactor Plant							
340			P	SG		-	-	-	-
341					B2	-	-	-	-
342									
343	531	Maintenance of Electric Plant							
344			P	SG		-	-	-	-
345					B2	-	-	-	-
346									
347	532	Maintenance of Misc Nuclear							
348			P	SG		-	-	-	-
349					B2	-	-	-	-
350									
351	**Total Nuclear Power Generation**				**B2**	**-**	**-**	**-**	**-**
352									
353	535	Operation Super & Engineering							
354			P	SG		-	-	1,444,992	376,025
355			P	SG		-	-	782,848	203,718
356			P	SG		-	-	49,841	12,970
357			P	SG		7,989,309	2,079,029	7,989,309	2,079,029
358			P	SG		823,116	214,196	823,116	214,196
359									
360					B2	8,812,425	2,293,225	11,090,106	2,885,938
361									
362	536	Water For Power							
363			P	SG		-	-	133	35
364			P	SG		39,247	10,213	39,247	10,213
365			P	SG		-	-	-	-
366									
367					B2	39,247	10,213	39,380	10,248
368									
369	537	Hydraulic Expenses							
370			P	SG		-	-	75,098	19,543
371			P	SG		4,073,258	1,059,969	4,073,258	1,059,969
372			P	SG		368,745	95,957	368,745	95,957
373									
374					B2	4,442,003	1,155,926	4,517,101	1,175,469

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
538	Electric Expenses							
		P	DGP		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B2	-	-	-	-
539	Misc. Hydro Expenses							
		P	SG		-	-	154,281	40,148
		P	SG		12,329,988	3,208,588	12,329,988	3,208,588
		P	SG		7,222,447	1,879,471	7,222,447	1,879,471
				B2	19,552,436	5,088,058	19,706,717	5,128,207
540	Rents (Hydro Generation)							
		P	SG		-	-	26,515	6,900
		P	SG		1,260,371	327,982	1,260,371	327,982
		P	SG		53,740	13,985	53,740	13,985
				B2	1,314,111	341,966	1,340,626	348,866
541	Maint Supervision & Engineering							
		P	SG		-	-	14	4
		P	SG		470	122	470	122
		P	SG		-	-	-	-
				B2	470	122	484	126
542	Maintenance of Structures							
		P	SG		-	-	7,239	1,884
		P	SG		487,433	126,843	487,433	126,843
		P	SG		26,209	6,820	26,209	6,820
				B2	513,642	133,663	520,881	135,547
543	Maintenance of Dams & Waterways							
		P	SG		-	-	25,594	6,660
		P	SG		941,650	245,042	941,650	245,042
		P	SG		629,929	163,924	629,929	163,924
				B2	1,571,579	408,966	1,597,173	415,627
544	Maintenance of Electric Plant							
		P	SG		-	-	18,666	4,857
		P	SG		1,701,465	442,766	1,701,465	442,766
		P	SG		292,333	76,073	292,333	76,073
				B2	1,993,798	518,839	2,012,464	523,696
545	Maintenance of Misc. Hydro Plant							
		P	SG		-	-	321,941	83,778
		P	SG		-	-	77,100	20,064
		P	SG		-	-	106,434	27,697
		P	SG		3,365,693	875,842	3,365,693	875,842
		P	SG		706,408	183,826	706,408	183,826
				B2	4,072,101	1,059,668	4,577,577	1,191,206
Total Hydraulic Power Generation				**B2**	**42,311,811**	**11,010,647**	**45,402,509**	**11,814,928**
546	Operation Super & Engineering							
		P	SG		280,415	72,971	280,415	72,971
		P	SG		-	-	-	-
		P	SG		-	-	11,795	3,069
				B2	280,415	72,971	292,210	76,041
547	Fuel-Non-NPC							
		P	SE		-	-	-	-
		P	SE		-	-	-	-
				B2	-	-	-	-
547NPC	Fuel-NPC							
		P	SE		268,434,763	67,381,120	305,707,467	76,737,123
		P	SE		1,064,775	267,274	1,064,775	267,274
				B2	269,499,538	67,648,394	306,772,242	77,004,397

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
548	Generation Expense							
		P	SG		17,053,590	4,437,793	17,053,590	4,437,793
		P	SG		717,121	186,614	717,121	186,614
		P	SG		-	-	1,436,131	373,719
				B2	17,770,711	4,624,407	19,206,842	4,998,126
549	Miscellaneous Other							
		P	S		96,122	96,122	102,412	102,412
		P	SG		3,633,672	945,577	3,633,672	945,577
		P	SG		1,479,164	384,917	1,479,164	384,917
		P	SG		-	-	20,061,025	5,220,407
		P	SG		-	-	-	-
				B2	5,208,958	1,426,617	25,276,273	6,653,313
550	Rents							
		P	S		288,047	288,047	296,505	296,505
		P	SG		-	-	107,070	27,863
		P	SG		39,499	10,279	39,499	10,279
		P	SG		3,606,840	938,595	3,606,840	938,595
				B2	3,934,386	1,236,920	4,049,915	1,273,241
551	Maint Supervision & Engineering							
		P	SG		-	-	-	-
				B2	-	-	-	-
552	Maintenance of Structures							
		P	SG		2,826,932	735,642	2,826,932	735,642
		P	SG		103,131	26,837	103,131	26,837
		P	SG		-	-	68,115	17,725
				B2	2,930,062	762,479	2,998,177	780,204
553	Maint of Generation & Electric Plant							
		P	SG		4,560,215	1,186,688	4,560,215	1,186,688
		P	SG		9,767,154	2,541,671	9,767,154	2,541,671
		P	SG		368,894	95,996	368,894	95,996
		P	SG		-	-	1,555,581	404,803
				B2	14,696,262	3,824,354	16,251,843	4,229,157
554	Maintenance of Misc. Other							
		P	SG		1,937,065	504,075	1,937,065	504,075
		P	SG		968,293	251,975	968,293	251,975
		P	SG		163,067	42,434	163,067	42,434
		P	SG		-	-	106,971	27,837
				B2	3,068,425	798,485	3,175,396	826,322
Total Other Power Generation				**B2**	**317,388,758**	**80,394,628**	**378,022,898**	**95,840,802**
555	Purchased Power-Non NPC							
		DMSC	S		(69,142,527)	-	(69,142,527)	-
					(69,142,527)	-	(69,142,527)	-
555NPC	Purchased Power-NPC							
		P	S		3,755,804	-	786,770	786,770
		P	SE		11,756	2,951	15,046,383	3,776,866
	Seasonal Cont	P	SG		729,221,964	189,762,752	597,467,355	155,476,734
		P	DGP		-	-	-	-
					732,989,524	189,765,703	613,300,508	160,040,371
	Total Purchased Power			B2	663,846,997	189,765,703	544,157,981	160,040,371
556	System Control & Load Dispatch							
		P	SG		909,957	236,795	921,767	239,868
				B2	909,957	236,795	921,767	239,868
557	Other Expenses							
		P	S		5,529,036	1,682,582	5,695,598	1,731,989
		P	SG		35,879,207	9,336,714	40,615,318	10,569,175
		P	SGCT		-	-	-	-
		P	SE		9,184	2,305	9,453	2,373
		P	SG		-	-	-	-
		P	TROJP		-	-	-	-
				B2	41,417,427	11,021,601	46,320,369	12,303,537

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Line	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS 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	**Total Other Power Supply**				**B2**	**696,009,922**	**190,024,099**	**581,235,659**	**161,583,776**
556									
557	**Total Production Expense**				**B2**	**2,155,677,074**	**561,720,509**	**1,979,029,913**	**516,549,884**
558									
559									
560	Summary of Production Expense by Factor								
561		S				(67,493,336)	(7,051,312)	(72,566,647)	(8,087,864)
562		SG				1,164,091,683	302,927,302	1,048,313,646	272,798,808
563		SE				1,059,078,727	265,844,519	1,003,282,914	251,838,940
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					2,155,677,074	561,720,509	1,979,029,913	516,549,884
580	560	Operation Supervision & Engineering							
581			T	SG		7,289,449	1,896,906	7,289,449	1,896,906
582			T	SG		-	-	2,133,839	555,281
583									
584					B2	7,289,449	1,896,906	9,423,288	2,452,188
585									
586	561	Load Dispatching							
587			T	SG		19,997,379	5,203,844	19,997,379	5,203,844
588			T	SG		-	-	206,895	53,840
589									
590					B2	19,997,379	5,203,844	20,204,274	5,257,684
591	562	Station Expense							
592			T	SG		2,788,755	725,707	2,788,755	725,707
593			T	SG		-	-	21,820	5,678
594									
595					B2	2,788,755	725,707	2,810,574	731,385
596									
597	563	Overhead Line Expense							
598			T	SG		1,038,410	270,222	1,038,410	270,222
599			T	SG		-	-	9,752	2,538
600									
601					B2	1,038,410	270,222	1,048,161	272,759
602									
603	564	Underground Line Expense							
604			T	SG		-	-	-	-
605									
606					B2	-	-	-	-
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		143,000,130	37,212,398	136,378,929	35,489,387
615			T	SE		(1,670,995)	(419,445)	2,694,259	676,299
616						141,329,135	36,792,954	139,073,187	36,165,687
617									
618		Total Transmission of Electricity by Others			B2	141,329,135	36,792,954	139,073,187	36,165,687

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
566	Misc. Transmission Expense							
		T	SG		2,871,698	747,291	2,871,698	747,291
		T	SG		-	-	60,218	15,670
				B2	2,871,698	747,291	2,931,916	762,962
567	Rents - Transmission							
		T	SG		2,121,266	552,009	2,121,266	552,009
		T	SG		-	-	42,345	11,019
				B2	2,121,266	552,009	2,163,610	563,028
568	Maint Supervision & Engineering							
		T	SG		1,350,447	351,422	1,350,447	351,422
		T	SG		-	-	3,259	848
				B2	1,350,447	351,422	1,353,706	352,270
569	Maintenance of Structures							
		T	SG		5,806,560	1,511,020	5,806,560	1,511,020
		T	SG		-	-	78,444	20,413
				B2	5,806,560	1,511,020	5,885,004	1,531,433
570	Maintenance of Station Equipment							
		T	SG		11,856,292	3,085,319	11,856,292	3,085,319
		T	SG		-	-	142,536	37,092
				B2	11,856,292	3,085,319	11,998,828	3,122,411
571	Maintenance of Overhead Lines							
		T	SG		16,155,917	4,204,195	16,155,917	4,204,195
		T	SG		-	-	2,113,248	549,923
				B2	16,155,917	4,204,195	18,269,166	4,754,118
572	Maintenance of Underground Lines							
		T	SG		37,745	9,822	37,745	9,822
		T	SG		-	-	289	75
				B2	37,745	9,822	38,035	9,898
573	Maint of Misc. Transmission Plant							
		T	SG		150,799	39,242	150,799	39,242
		T	SG		-	-	4,603	1,198
				B2	150,799	39,242	155,402	40,440
Total Transmission Expense				**B2**	**212,793,850**	**55,389,954**	**215,355,152**	**56,016,262**
Summary of Transmission Expense by Factor								
		SE			(1,670,995)	(419,445)	2,694,259	676,299
		SG			214,464,845	55,809,399	212,660,893	55,339,963
		SNPT			-	-	-	-
Total Transmission Expense by Factor					212,793,850	55,389,954	215,355,152	56,016,262
580	Operation Supervision & Engineering							
		DPW	S		1,049,359	308,795	3,624,386	1,052,279
		DPW	SNPD		7,995,339	2,139,263	10,466,695	2,800,509
				B2	9,044,698	2,448,058	14,091,080	3,852,787
581	Load Dispatching							
		DPW	S		-	-	-	-
		DPW	SNPD		12,174,853	3,257,550	12,167,555	3,255,597
				B2	12,174,853	3,257,550	12,167,555	3,255,597
582	Station Expense							
		DPW	S		4,674,701	1,050,441	4,760,024	1,075,700
		DPW	SNPD		3,667	981	3,681	985
				B2	4,678,369	1,051,422	4,763,705	1,076,685
583	Overhead Line Expenses							
		DPW	S		9,086,257	1,649,556	9,169,847	1,661,832
		DPW	SNPD		163	44	163	44
				B2	9,086,420	1,649,600	9,170,010	1,661,875
584	Underground Line Expense							
		DPW	S		1,746	483	1,808	545
		DPW	SNPD		-	-	-	-
				B2	1,746	483	1,808	545
585	Street Lighting & Signal Systems							
		DPW	S		-	-	-	-
		DPW	SNPD		212,694	56,909	212,859	56,953
				B2	212,694	56,909	212,859	56,953

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
586	Meter Expenses							
		DPW	S		2,624,679	741,264	2,642,219	747,014
		DPW	SNPD		-	-	-	-
				B2	2,624,679	741,264	2,642,219	747,014
587	Customer Installation Expenses							
		DPW	S		14,776,621	5,498,261	14,893,968	5,540,670
		DPW	SNPD		-	-	-	-
				B2	14,776,621	5,498,261	14,893,968	5,540,670
588	Misc. Distribution Expenses							
		DPW	S		(183,942)	78,056	(186,816)	80,257
		DPW	SNPD		871,343	233,140	797,669	213,427
				B2	687,402	311,196	610,852	293,685
589	Rents							
		DPW	S		2,846,644	1,590,360	2,930,608	1,644,054
		DPW	SNPD		12,973	3,471	13,435	3,595
				B2	2,859,617	1,593,831	2,944,043	1,647,649
590	Maint Supervision & Engineering							
		DPW	S		3,451,251	948,653	3,460,068	951,464
		DPW	SNPD		2,489,002	665,967	2,490,249	666,300
				B2	5,940,253	1,614,620	5,950,317	1,617,764
591	Maintenance of Structures							
		DPW	S		2,149,515	438,530	2,210,506	450,973
		DPW	SNPD		180,852	48,389	185,983	49,762
				B2	2,330,367	486,919	2,396,489	500,735
592	Maintenance of Station Equipment							
		DPW	S		7,841,238	2,644,907	7,908,647	2,666,737
		DPW	SNPD		1,853,390	495,900	1,856,918	496,844
				B2	9,694,628	3,140,807	9,765,566	3,163,581
593	Maintenance of Overhead Lines							
		DPW	S		87,107,242	27,978,322	101,412,208	35,707,602
		DPW	SNPD		2,197,739	588,035	3,015,632	806,874
				B2	89,304,980	28,566,357	104,427,840	36,514,476
594	Maintenance of Underground Lines							
		DPW	S		25,749,537	6,234,963	26,099,238	6,307,761
		DPW	SNPD		24,641	6,593	24,767	6,627
				B2	25,774,177	6,241,556	26,124,005	6,314,388
595	Maintenance of Line Transformers							
		DPW	S		-	-	-	-
		DPW	SNPD		957,891	256,297	962,712	257,587
				B2	957,891	256,297	962,712	257,587
596	Maint of Street Lighting & Signal Sys.							
		DPW	S		2,907,881	849,569	2,952,130	856,129
		DPW	SNPD		-	-	-	-
				B2	2,907,881	849,569	2,952,130	856,129
597	Maintenance of Meters							
		DPW	S		641,735	258,545	645,584	260,199
		DPW	SNPD		(265,353)	(70,999)	(266,327)	(71,260)
				B2	376,382	187,547	379,257	188,939
598	Maint of Misc. Distribution Plant							
		DPW	S		1,755,437	619,578	1,803,501	635,939
		DPW	SNPD		5,648,503	1,511,335	5,767,408	1,543,150
				B2	7,403,940	2,130,913	7,570,910	2,179,089
Total Distribution Expense				**B2**	**200,837,597**	**60,083,160**	**222,027,327**	**69,726,150**
Summary of Distribution Expense by Factor								
	S				166,479,901	50,890,284	184,327,928	59,639,155
	SNPD				34,357,696	9,192,876	37,699,399	10,086,994
Total Distribution Expense by Factor					200,837,597	60,083,160	222,027,327	69,726,150
901	Supervision							
		CUST	S		178	-	187	-
		CUST	CN		2,689,357	839,538	2,721,142	849,460
				B2	2,689,535	839,538	2,721,329	849,460

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
902	Meter Reading Expense							
		CUST	S		16,478,688	7,223,864	16,674,375	7,318,815
		CUST	CN		743,635	232,141	756,503	236,158
				B2	17,222,323	7,456,005	17,430,878	7,554,973
903	Customer Receipts & Collections							
		CUST	S		6,621,316	1,745,123	8,572,625	2,449,632
		CUST	CN		41,740,807	13,030,252	45,738,942	14,278,353
				B2	48,362,122	14,775,376	54,311,567	16,727,984
904	Uncollectible Accounts							
		CUST	S		13,273,070	4,630,969	14,128,057	5,041,346
		P	SG		-	-	-	-
		CUST	CN		64,325	20,080	67,634	21,113
				B2	13,337,395	4,651,050	14,195,691	5,062,459
905	Misc. Customer Accounts Expense							
		CUST	S		416,830	-	438,274	-
		CUST	CN		22,019	6,874	23,152	7,227
				B2	438,849	6,874	461,426	7,227
Total Customer Accounts Expense				**B2**	**82,050,225**	**27,728,842**	**89,120,892**	**30,202,104**
Summary of Customer Accts Exp by Factor								
	S				36,790,081	13,599,956	39,813,519	14,809,793
	CN				45,260,144	14,128,886	49,307,374	15,392,312
	SG				-	-	-	-
Total Customer Accounts Expense by Factor					82,050,225	27,728,842	89,120,892	30,202,104
907	Supervision							
		CUST	S		-	-	-	-
		CUST	CN		165	51	523	163
				B2	165	51	523	163
908	Customer Assistance							
		CUST	S		89,487,408	2,096,459	93,447,165	2,317,803
		CUST	CN		2,701,624	843,367	3,093,132	965,585
				B2	92,189,031	2,939,827	96,540,297	3,283,388
909	Informational & Instructional Adv							
		CUST	S		4,400,114	1,894,445	4,634,501	2,007,072
		CUST	CN		2,687,097	838,833	2,708,105	845,391
				B2	7,087,211	2,733,277	7,342,606	2,852,463
910	Misc. Customer Service							
		CUST	S		-	-	-	-
		CUST	CN		16,171	5,048	17,031	5,317
				B2	16,171	5,048	17,031	5,317
Total Customer Service Expense				**B2**	**99,292,578**	**5,678,204**	**103,900,457**	**6,141,331**
Summary of Customer Service Exp by Factor								
	S				93,887,521	3,990,904	98,081,666	4,324,875
	CN				5,405,056	1,687,300	5,818,791	1,816,455
Total Customer Service Expense by Factor				B2	99,292,578	5,678,204	103,900,457	6,141,331
911	Supervision							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
912	Demonstration & Selling Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
913	Advertising Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	 OREGON
916	Misc. Sales Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
Total Sales Expense				**B2**	**-**	**-**	**-**	**-**
Total Sales Expense by Factor								
	S				-	-	-	-
	CN				-	-	-	-
Total Sales Expense by Factor					-	-	-	-
Total Customer Service Exp Including Sales				**B2**	**99,292,578**	**5,678,204**	**103,900,457**	**6,141,331**
920	Administrative & General Salaries							
		PTD	S		(38)	(39)	47,744	9,198
		CUST	CN		-	-	-	-
		PTD	SO		73,780,564	20,079,611	78,796,419	21,444,692
				B2	73,780,526	20,079,572	78,844,163	21,453,889
921	Office Supplies & expenses							
		PTD	S		270,856	56,778	281,601	59,030
		CUST	CN		89,293	27,875	92,835	28,980
		PTD	SO		9,148,245	2,489,724	10,963,206	2,983,671
				B2	9,508,394	2,574,376	11,337,643	3,071,681
922	A&G Expenses Transferred							
		PTD	S		-	-	-	-
		CUST	CN		-	-	-	-
		PTD	SO		(33,020,274)	(8,986,571)	(33,352,793)	(9,077,067)
				B2	(33,020,274)	(8,986,571)	(33,352,793)	(9,077,067)
923	Outside Services							
		PTD	S		1,550,477	123,975	1,621,801	129,678
		CUST	CN		-	-	-	-
		PTD	SO		21,001,084	5,715,511	21,951,555	5,974,184
				B2	22,551,561	5,839,486	23,573,356	6,103,862
924	Property Insurance							
		PT	S		10,379,773	6,295,833	11,913,743	7,829,803
		PT	SG		-	-	-	-
		PTD	SO		4,722,691	1,285,295	2,861,661	778,810
				B2	15,102,464	7,581,128	14,775,404	8,608,613
925	Injuries & Damages							
		PTD	S		(21,503)	(21,503)	1,096,772	1,096,772
		PTD	SO		17,313,348	4,711,882	7,038,230	1,915,476
				B2	17,291,845	4,690,379	8,135,002	3,012,248
926	Employee Pensions & Benefits							
		LABOR	S		(68,187)	(407,236)	(3,715,909)	(4,122,384)
		CUST	CN		-	-	-	-
		LABOR	SO		118,045,638	32,126,489	130,491,868	35,513,770
				B2	117,977,451	31,719,254	126,775,959	31,391,385
927	Franchise Requirements							
		DMSC	S		-	-	-	-
		DMSC	SO		-	-	-	-
				B2	-	-	-	-
928	Regulatory Commission Expense							
		DMSC	S		14,733,573	4,070,427	15,567,765	4,437,868
		P	SE		8,083	2,029	8,083	2,029
		DMSC	SO		3,155,077	858,664	3,311,892	901,342
		FERC	SG		5,233,705	1,361,948	5,481,786	1,426,505
				B2	23,130,437	6,293,068	24,369,526	6,767,743
929	Duplicate Charges							
		LABOR	S		-	-	-	-
		LABOR	SO		(130,126,920)	(35,414,448)	(139,246,897)	(37,896,478)
				B2	(130,126,920)	(35,414,448)	(139,246,897)	(37,896,478)
930	Misc General Expenses							
		PTD	S		42,496	33,354	9,292	(665)
		CUST	CN		-	-	-	-
		P	SG		-	-	-	-
		LABOR	SO		2,160,475	587,980	1,663,708	452,783
				B2	2,202,972	621,334	1,673,000	452,118

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	 OREGON
938									
939	931	Rents							
940			PTD	S		420,480	259,287	443,783	273,657
941			PTD	SO		2,138,243	581,929	2,256,746	614,180
942					B2	2,558,723	841,216	2,700,529	887,837
943									
944	935	Maintenance of General Plant							
945			G	S		471,629	167,285	483,407	172,151
946			CUST	CN		59,158	18,467	60,431	18,865
947			G	SO		23,213,078	6,317,512	23,905,669	6,506,002
948					B2	23,743,865	6,503,264	24,449,507	6,697,019
949									
950	**Total Administrative & General Expense**				**B2**	**144,701,044**	**42,342,058**	**144,034,397**	**41,472,852**
951									
952	Summary of A&G Expense by Factor								
953		S				27,779,556	10,578,161	27,749,999	9,885,107
954		SE				8,083	2,029	8,083	2,029
955		SO				111,531,250	30,353,578	110,641,264	30,111,366
956		SG				5,233,705	1,361,948	5,481,786	1,426,505
957		CN				148,451	46,342	153,266	47,845
958	Total A&G Expense by Factor					144,701,044	42,342,058	144,034,397	41,472,852
959									
960	**Total O&M Expense**				**B2**	**2,895,352,368**	**752,942,727**	**2,753,468,138**	**720,108,582**
961	403SP	Steam Depreciation							
962			P	SG		30,169,736	7,850,960	30,169,736	7,850,960
963			P	SG		30,130,900	7,840,853	30,130,900	7,840,853
964			P	SG		170,224,168	44,296,810	453,747,944	118,077,160
965			P	SG		15,145,184	3,941,176	15,145,184	3,941,176
966					B3	245,669,987	63,929,798	529,193,763	137,710,149
967									
968	403NP	Nuclear Depreciation							
969			P	SG		-	-	-	-
970					B3	-	-	-	-
971									
972	403HP	Hydro Depreciation							
973			P	SG		(74,556)	(19,402)	(74,556)	(19,402)
974			P	SG		1,386,317	360,756	1,386,317	360,756
975			P	SG		32,698,277	8,508,952	18,244,739	4,747,761
976			P	SG		5,919,818	1,540,493	7,582,325	1,973,121
977			P	SG		-	-	4,057,251	1,055,803
978					B3	39,929,856	10,390,800	31,196,075	8,118,040
979									
980	403OP	Other Production Depreciation							
981			p	S		-	-	5,998	5,998
982			P	SG		-	-	-	-
983			P	SG		57,519,990	14,968,216	180,808,870	47,051,228
984			P	SG		3,259,020	848,083	3,259,020	848,083
985			P	SG		67,675,190	17,610,866	50,049,597	13,024,223
986					B3	128,454,199	33,427,164	234,123,484	60,929,531
987									
988	403TP	Transmission Depreciation							
989			T	SG		8,665,935	2,255,104	8,665,935	2,255,104
990			T	SG		10,823,573	2,816,579	10,823,573	2,816,579
991			T	SG		91,403,582	23,785,618	122,386,372	31,848,156
992					B3	110,893,089	28,857,301	141,875,879	36,919,839
993									
994									
995									
996	403	Distribution Depreciation							
997	360	Land & Land Rights	DPW	S		428,924	61,992	818,259	112,505
998	361	Structures	DPW	S		2,085,151	572,195	2,831,062	668,970
999	362	Station Equipment	DPW	S		(4,092,588)	5,417,172	2,170,270	6,229,726
1000	363	Storage Battery Equip	DPW	S		-	-	-	-
1001	364	Poles & Towers	DPW	S		43,265,700	12,836,209	50,803,359	13,814,159
1002	365	OH Conductors	DPW	S		20,500,784	7,071,868	25,295,959	7,694,002
1003	366	UG Conduit	DPW	S		9,409,489	1,906,326	11,787,792	2,214,891
1004	367	UG Conductor	DPW	S		22,043,207	3,968,159	27,595,653	4,688,543
1005	368	Line Trans	DPW	S		34,230,814	11,126,561	42,782,583	12,236,082
1006	369	Services	DPW	S		18,920,122	6,776,031	24,041,019	7,440,425
1007	370	Meters	DPW	S		8,681,662	3,046,879	10,130,751	3,234,886
1008	371	Inst Cust Prem	DPW	S		496,701	126,330	550,473	133,307
1009	372	Leased Property	DPW	S		-	-	-	-
1010	373	Street Lighting	DPW	S		2,235,385	698,542	2,618,063	748,191
1011					B3	158,205,353	53,608,264	201,425,242	59,215,689

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	 OREGON
403GP	General Depreciation							
		G-SITUS	S		14,773,471	5,078,614	17,390,023	5,794,774
		G-DGP	SG		23,762	6,183	23,762	6,183
		G-DGU	SG		73,045	19,008	73,045	19,008
		P	SE		95,328	23,929	117,402	29,470
		CUST	CN		1,040,345	324,765	846,011	264,100
		G-SG	SG		9,665,735	2,515,279	10,193,953	2,652,735
		PTD	SO		15,567,254	4,236,677	17,861,183	4,860,977
		G-SG	SG		8,187	2,130	8,187	2,130
		G-SG	SG		144,337	37,560	144,337	37,560
				B3	41,391,464	12,244,146	46,657,902	13,666,937
403GV0	General Vehicles							
		G-SG	SG		-	-	-	-
				B3	-	-	-	-
403MP	Mining Depreciation							
		P	SE		-	-	-	-
				B3	-	-	-	-
403EP	Experimental Plant Depreciation							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B3	-	-	-	-
4031	ARO Depreciation							
		P	S		-	-	-	-
				B3	-	-	-	-
Total Depreciation Expense				**B3**	**724,543,948**	**202,457,473**	**1,184,472,345**	**316,560,184**
Summary	S				172,978,823	58,686,878	218,821,262	65,016,460
	DGP				-	-	-	-
	DGU				-	-	-	-
	SG				534,862,197	139,185,224	946,826,488	246,389,178
	SO				15,567,254	4,236,677	17,861,183	4,860,977
	CN				1,040,345	324,765	846,011	264,100
	SE				95,328	23,929	117,402	29,470
	SSGCH				-	-	-	-
	SSGCT				-	-	-	-
Total Depreciation Expense By Factor					724,543,948	202,457,473	1,184,472,345	316,560,184
404GP	Amort of LT Plant - Leasehold Improvements							
		I-SITUS	S		576,525	308,163	407,271	249,902
		I-SG	SG		-	-	-	-
		PTD	SO		289,934	78,906	284,353	77,388
		I-DGU	SG		-	-	-	-
		CUST	CN		-	-	-	-
		I-DGP	SG		-	-	-	-
				B4	866,459	387,070	691,624	327,289
404SP	Amort of LT Plant - Cap Lease Steam							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B4	-	-	-	-
404IP	Amort of LT Plant - Intangible Plant							
		I-SITUS	S		821,777	10,341	985,326	13,738
		P	SE		1,239	311	-	-
		I-SG	SG		14,326,925	3,728,243	7,640,713	1,988,315
		PTD	SO		10,992,229	2,991,570	16,442,185	4,474,792
		CUST	CN		9,726,915	3,036,457	10,650,150	3,324,664
		I-SG	SG		10,915,568	2,840,518	2,616,793	680,958
		I-SG	SG		315,841	82,190	314,803	81,920
		I-DGP	SG		78,646	20,466	78,646	20,466
		I-SG	SG		-	-	-	-
		I-SG	SG		21,649	5,634	21,649	5,634
		I-DGU	SG		16,485	4,290	16,485	4,290
				B4	47,217,274	12,720,019	38,766,749	10,594,776
404MP	Amort of LT Plant - Mining Plant							
		P	SE		-	-	-	-
				B4	-	-	-	-
404OP	Amort of LT Plant - Other Plant							
		P	SG		-	-	-	-
				B4	-	-	-	-

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
1092	404HP	Amortization of Other Electric Plant							
1093			P	SG		311,125	80,963	311,696	81,111
1094			P	SG		-	-	-	-
1095			P	SG		-	-	-	-
1096					B4	311,125	80,963	311,696	81,111
1097									
1098	**Total Amortization of Limited Term Plant**				**B4**	**48,394,858**	**13,188,051**	**39,770,069**	**11,003,177**
1099									
1100									
1101	405	Amortization of Other Electric Plant							
1102			GP	S		-	-	-	-
1103									
1104					B4	-	-	-	-
1105									
1106	406	Amortization of Plant Acquisition Adj							
1107			P	S		301,635	-	301,635	-
1108			P	SG		-	-	-	-
1109			P	SG		-	-	-	-
1110			P	SG		4,781,559	1,244,288	4,781,559	1,244,288
1111			P	SO		-	-	-	-
1112					B4	5,083,195	1,244,288	5,083,195	1,244,288
1113	407	Amort of Prop Losses, Unrec Plant, etc							
1114			DPW	S		124,290	(966)	(1,670,947)	(1,796,203)
1115			GP	SO		-	-	-	-
1116			P	SG-P		-	-	-	-
1117			P	SE		-	-	-	-
1118			P	SG		-	-	40,889,628	10,640,558
1119			P	TROJP		-	-	-	-
1120					B4	124,290	(966)	39,218,681	8,844,354
1121									
1122	**Total Amortization Expense**				**B4**	**53,602,343**	**14,431,373**	**84,071,945**	**21,091,819**
1123									
1124									
1125									
1126	Summary of Amortization Expense by Factor								
1127		S				1,824,227	317,539	23,285	(1,532,563)
1128		SE				1,239	311	-	-
1129		TROJP				-	-	-	-
1130		DGP				-	-	-	-
1131		DGU				-	-	-	-
1132		SO				11,282,163	3,070,476	16,726,538	4,552,180
1133		SSGCT				-	-	-	-
1134		SSGCH				-	-	-	-
1135		CN				9,726,915	3,036,457	10,650,150	3,324,664
1136		SG				30,767,798	8,006,591	56,671,972	14,747,539
1137	Total Amortization Expense by Factor					53,602,343	14,431,373	84,071,945	21,091,819
1138	408	Taxes Other Than Income							
1139			DMSC	S		35,011,797	31,803,625	36,118,093	32,909,920
1140			GP	GPS		149,370,144	40,651,551	181,331,121	49,349,831
1141			GP	SO		12,360,904	3,364,059	12,360,904	3,364,059
1142			P	SE		843,248	211,668	843,248	211,668
1143			P	SG		1,955,572	508,891	1,989,171	517,635
1144			DMSC	OPRV-ID		-	-	-	-
1145			GP	EXCTAX		-	-	-	-
1146			GP	SG		-	-	-	-
1147									
1148									
1149									
1150	**Total Taxes Other Than Income**				**B5**	**199,541,666**	**76,539,794**	**232,642,537**	**86,353,112**
1151									
1152									
1153	41140	Deferred Investment Tax Credit - Fed							
1154			PTD	DGU		(2,943,987)	-	(2,943,987)	-
1155									
1156					B7	(2,943,987)	-	(2,943,987)	-
1157									
1158	41141	Deferred Investment Tax Credit - Idaho							
1159			PTD	DGU		-	-	-	-
1160									
1161					B7	-	-	-	-
1162									
1163	**Total Deferred ITC**				**B7**	**(2,943,987)**	**-**	**(2,943,987)**	**-**
1164									
1165									
1166	427	Interest on Long-Term Debt							
1167			GP	S		309,427,205	82,377,974	363,363,587	92,980,612
1168			GP	SNP		-	-	-	-
1169					B6	309,427,205	82,377,974	363,363,587	92,980,612

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
1170									
1171	428	Amortization of Debt Disc & Exp							
1172			GP	SNP		4,460,171	1,172,671	4,460,171	1,172,671
1173					B6	4,460,171	1,172,671	4,460,171	1,172,671
1174									
1175	429	Amortization of Premium on Debt							
1176			GP	SNP		(11,026)	(2,899)	(11,026)	(2,899)
1177					B6	(11,026)	(2,899)	(11,026)	(2,899)
1178									
1179	431	Other Interest Expense							
1180			NUTIL	OTH		-	-	-	-
1181			GP	SO		-	-	-	-
1182			GP	SNP		21,988,458	5,781,217	21,988,458	5,781,217
1183					B6	21,988,458	5,781,217	21,988,458	5,781,217
1184									
1185	432	AFUDC - Borrowed							
1186			GP	SNP		(25,466,792)	(6,695,742)	(25,466,792)	(6,695,742)
1187						(25,466,792)	(6,695,742)	(25,466,792)	(6,695,742)
1188									
1189		Total Elec. Interest Deductions for Tax			B6	310,398,017	82,633,220	364,334,399	93,235,859
1190									
1191		Non-Regulated Portion of Interest							
1192		427	NUTIL	NUTIL		-	-	-	-
1193		428	NUTIL	NUTIL		-	-	-	-
1194		429	NUTIL	NUTIL		-	-	-	-
1195		431	NUTIL	NUTIL		-	-	-	-
1196									
1197		Total Non-Regulated Interest				-	-	-	-
1198									
1199		Total Interest Deductions for Tax			B6	310,398,017	82,633,220	364,334,399	93,235,859
1200									
1201									
1202	419	Interest & Dividends							
1203			GP	S		-	-	-	-
1204			GP	SNP		(49,461,258)	(13,004,380)	(71,759,910)	(18,867,154)
1205		Total Operating Deductions for Tax			B6	(49,461,258)	(13,004,380)	(71,759,910)	(18,867,154)
1206									
1207									
1208	41010	Deferred Income Tax - Federal-DR							
1209			GP	S		17,770,795	(312,672)	(2,220,328)	2,485,004
1210			P	TROJD		-	-	-	-
1211			PT	SG		83,511	21,732	83,511	21,732
1212			LABOR	SO		5,670,881	1,543,348	5,886,992	1,602,163
1213			GP	SNP		18,367,499	4,829,193	24,895,341	6,545,496
1214			P	SE		(288,054)	(72,306)	(4,951,776)	(1,242,969)
1215			PT	SG		35,663,554	9,280,596	112,650,533	29,314,634
1216			GP	GPS		16,739,227	4,555,633	11,085,507	3,016,955
1217			DITEXP	DITEXP		-	-	-	-
1218			CUST	BADDEBT		-	-	-	-
1219			CUST	CN		-	-	-	-
1220			IBT	IBT		-	-	-	-
1221			DPW	CIAC		-	-	-	-
1222			GP	SCHMDEXP		-	-	-	-
1223			TAXDEPR	TAXDEPR		145,237,384	38,159,076	231,359,927	60,786,561
1224			DPW	SNPD		375,210	100,393	1	0
1225					B7	239,620,007	58,104,992	378,789,708	102,529,576
1226									
1227									
1228									
1229	41110	Deferred Income Tax - Federal-CR							
1230			GP	S		(130,056,939)	800,425	(75,655,657)	(14,328,322)
1231			P	SE		(8,667,169)	(2,175,588)	(8,211,900)	(2,061,309)
1232			PT	SG		(344,503)	(89,649)	(344,503)	(89,649)
1233			GP	SNP		(10,288,673)	(2,705,103)	(14,672,252)	(3,857,636)
1234			PT	SG		100,670	26,197	(107,861,864)	(28,068,497)
1235			GP	GPS		145,317	39,548	-	-
1236			LABOR	SO		(5,993,991)	(1,631,283)	(2,365,237)	(643,707)
1237			PT	SNPD		(516,039)	(138,073)	-	-
1238			CUST	BADDEBT		(97,689)	(34,838)	(0)	(0)
1239			P	SG		-	-	-	-
1240			DITEXP	SG		-	-	-	-
1241			P	TROJD		12,532	3,241	(1)	(0)
1242			IBT	CN		-	-	(1,855)	(579)
1243			DPW	CIAC		(25,324,501)	(6,775,920)	(18,185,604)	(4,865,809)
1244			GP	SCHMDEXP		(241,934,106)	(64,658,922)	(225,069,075)	(60,151,601)
1245			TAXDEPR	TAXDEPR		-	-	-	-
1246					B7	(422,965,091)	(77,339,966)	(452,367,948)	(114,067,109)
1247									
1248	**Total Deferred Income Taxes**				**B7**	**(183,345,084)**	**(19,234,974)**	**(73,578,240)**	**(11,537,533)**

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
SCHMAF	Additions - Flow Through							
		SCHMAF	S		-	-	-	-
		SCHMAF	SNP		-	-	-	-
		SCHMAF	SO		-	-	-	-
		SCHMAF	SE		-	-	-	-
		SCHMAF	TROJP		-	-	-	-
		SCHMAF	SG		-	-	-	-
				B6	-	-	-	-
SCHMAP	Additions - Permanent							
		P	S		-	-	-	-
		P	SE		58,125	14,590	18,000	4,518
		LABOR	SNP		-	-	-	-
		SCHMAP-SO	SO		2,371,219	645,335	3,718,000	1,011,865
		SCHMAP	SG		-	-	-	-
		DPW	SCHMDEXP		129,290	34,554	143,074	38,238
				B6	2,558,634	694,479	3,879,074	1,054,621
SCHMAT	Additions - Temporary							
		SCHMAT-SITUS	S		13,263,811	(6,898,690)	(63,260,069)	(11,279,520)
		P	SG		-	-	-	-
		DPW	CIAC		103,001,232	27,559,401	73,965,511	19,790,493
		SCHMAT-SNP	SNP		41,846,673	11,002,349	59,675,808	15,689,995
		P	TROJD		(50,974)	(13,181)	0	0
		P	SG		-	-	-	-
		SCHMAT-SE	SE		35,251,596	8,848,675	33,399,929	8,383,879
		P	SG		(403,666)	(105,045)	449,280,984	116,914,740
		SCHMAT-GPS	GPS		(591,042)	(160,854)	0	0
		SCHMAT-SO	SO		24,379,109	6,634,851	9,620,041	2,618,124
		SCHMAT-SNP	SNPD		2,098,862	561,579	-	-
		CUST	BADDEBT		397,328	141,695	(0)	(0)
		P	CN		-	-	7,544	2,355
		BOOKDEPR	SCHMDEXP		984,007,982	262,984,399	915,413,585	244,651,971
				B6	1,203,200,912	310,555,181	1,478,103,333	396,772,036
TOTAL SCHEDULE - M ADDITIONS				B6	1,205,759,546	311,249,659	1,481,982,406	397,826,658
SCHMDF	Deductions - Flow Through							
		SCHMDF	S		-	-	-	-
		SCHMDF	DGP		-	-	-	-
		SCHMDF	DGU		-	-	-	-
				B6	-	-	-	-
SCHMDP	Deductions - Permanent							
		SCHMDP	S		-	-	-	-
		P	SE		-	-	3,545,057	889,862
		PTD	SNP		106,610	28,030	0	0
		BOOKDEPR	SCHMDEXP		(19,357)	(5,173)	525,184	140,360
		P	SG		-	-	-	-
		SCHMDP-SO	SO		-	-	-	-
				B6	87,253	22,857	4,070,241	1,030,222
SCHMDT	Deductions - Temporary							
		GP	S		72,278,358	(1,271,716)	(9,030,635)	10,107,177
		CUST	BADDEBT		-	-	-	-
		SCHMDT-SNP	SNP		74,705,322	19,641,563	101,255,730	26,622,210
		CUST	CN		-	-	-	-
		SCHMDT	SG		339,662	88,389	339,662	88,389
		CUST	DGP		-	-	-	-
		P	SE		(1,171,589)	(294,086)	(20,140,135)	(5,055,474)
		SCHMDT-SG	SG		145,052,807	37,746,559	468,249,242	121,850,780
		SCHMDT-GPS	GPS		68,082,721	18,528,925	45,087,598	12,270,731
		SCHMDT-SO	SO		23,064,917	6,277,189	23,943,900	6,516,407
		TAXDEPR	TAXDEPR		590,717,641	155,202,736	941,000,086	247,234,512
		DPW	SNPD		1,526,070	408,321	(0)	(0)
				B6	974,595,908	236,327,880	1,550,705,447	419,634,732
TOTAL SCHEDULE - M DEDUCTIONS				B6	974,683,161	236,350,736	1,554,775,689	420,664,954
TOTAL SCHEDULE - M ADJUSTMENTS				**B6**	**231,076,385**	**74,898,923**	**(72,793,282)**	**(22,838,296)**
40911	State Income Taxes							
		IBT			57,214,213	14,830,341	29,409,617	8,640,100
		IBT	IBT		-	-	-	-
	PTC	P	SG		-	-	-	-
		IBT	IBT		-	-	-	-
Total State Tax Expense					**57,214,213**	**14,830,341**	**29,409,617**	**8,640,100**

2020 PROTOCOL
Year End

Line	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
1329	Calculation of Taxable Income:								
1330		Operating Revenues				5,159,798,594	1,367,388,196	5,267,730,734	1,432,178,141
1331		Operating Deductions:							
1332		O & M Expenses				2,895,352,368	752,942,727	2,753,468,138	720,108,582
1333		Depreciation Expense				724,543,948	202,457,473	1,184,472,345	316,560,184
1334		Amortization Expense				53,602,343	14,431,373	84,071,945	21,091,819
1335		Taxes Other Than Income				199,541,666	76,539,794	232,642,537	86,353,112
1336		Interest & Dividends (AFUDC-Equity)				(49,461,258)	(13,004,380)	(71,759,910)	(18,867,154)
1337		Misc Revenue & Expense				(3,327,067)	(372,574)	(80,922)	546,879
1338		Total Operating Deductions				3,820,251,999	1,032,994,412	4,182,814,132	1,125,793,424
1339		Other Deductions:							
1340		Interest Deductions				310,398,017	82,633,220	364,334,399	93,235,859
1341		Interest on PCRBS				-	-	-	-
1342		Schedule M Adjustments				231,076,385	74,898,923	(72,793,282)	(22,838,296)
1343									
1344		Income Before State Taxes				1,260,224,963	326,659,487	647,788,920	190,310,563
1345									
1346		State Income Taxes				57,214,213	14,830,341	29,409,617	8,640,100
1347									
1348	Total Taxable Income					1,203,010,750	311,829,146	618,379,303	181,670,463
1349									
1350	Tax Rate					21.0%	21.0%	21.0%	21.0%
1351									
1352	Federal Income Tax - Calculated					252,632,257	65,484,121	129,859,654	38,150,797
1353									
1354	Adjustments to Calculated Tax:								
1355	40910		P	SE		(18,519)	(4,649)	(18,000)	(4,518)
1356	40910	PTC	P	SG		(45,352,770)	(11,801,985)	(187,272,740)	(48,733,297)
1357	40910		P	SO		(41,507)	(11,296)	-	-
1358	40910	IRS Settle	LABOR	S		-	-	-	-
1359	**Federal Income Tax Expense**					**207,219,461**	**53,666,191**	**(57,431,087)**	**(10,587,018)**
1360									
1361	**Total Operating Expenses**					**3,947,857,860**	**1,095,260,350**	**4,150,030,346**	**1,131,176,126**
1362	310	Land and Land Rights							
1363			P	SG		2,328,177	605,853	2,328,177	605,853
1364			P	SG		33,837,468	8,805,400	33,837,468	8,805,400
1365			P	SG		54,188,889	14,101,375	54,188,889	14,101,375
1366			P	S		-	-	-	-
1367			P	SG		2,635,317	685,779	2,635,317	685,779
1368					B8	92,989,851	24,198,407	92,989,851	24,198,407
1369									
1370	311	Structures and Improvements							
1371			P	SG		227,138,030	59,107,295	227,138,030	59,107,295
1372			P	SG		314,032,398	81,719,497	314,032,398	81,719,497
1373			P	SG		429,854,817	111,859,540	429,854,817	111,859,540
1374			P	SG		65,501,187	17,045,133	65,501,187	17,045,133
1375					B8	1,036,526,432	269,731,465	1,036,526,432	269,731,465
1376									
1377	312	Boiler Plant Equipment							
1378			P	SG		591,094,231	153,818,280	591,094,231	153,818,280
1379			P	SG		468,246,188	121,849,985	468,246,188	121,849,985
1380			P	SG		3,210,660,584	835,498,407	2,757,133,558	717,478,735
1381			P	SG		341,888,910	88,968,495	341,888,910	88,968,495
1382					B8	4,611,889,914	1,200,135,167	4,158,362,888	1,082,115,495
1383									
1384	314	Turbogenerator Units							
1385			P	SG		109,569,676	28,512,914	109,569,676	28,512,914
1386			P	SG		109,731,202	28,554,947	109,731,202	28,554,947
1387			P	SG		713,024,372	185,547,712	713,024,372	185,547,712
1388			P	SG		69,096,130	17,980,632	69,096,130	17,980,632
1389					B8	1,001,421,379	260,596,206	1,001,421,379	260,596,206
1390									
1391	315	Accessory Electric Equipment							
1392			P	SG		86,091,816	22,403,357	86,091,816	22,403,357
1393			P	SG		133,452,442	34,727,839	133,452,442	34,727,839
1394			P	SG		199,968,303	52,037,017	199,968,303	52,037,017
1395			P	SG		68,681,644	17,872,772	68,681,644	17,872,772
1396					B8	488,194,205	127,040,984	488,194,205	127,040,984
1397									
1398									
1399									
1400	316	Misc Power Plant Equipment							
1401			P	SG		2,593,134	674,802	2,593,134	674,802
1402			P	SG		4,977,072	1,295,165	4,977,072	1,295,165
1403			P	SG		21,305,517	5,544,256	21,305,517	5,544,256
1404			P	SG		4,159,337	1,082,369	4,159,337	1,082,369
1405					B8	33,035,060	8,596,592	33,035,060	8,596,592

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
1406									
1407	317	Steam Plant ARO							
1408			P	S		-	-	-	-
1409					B8	-	-	-	-
1410									
1411	SP	Unclassified Steam Plant - Account 300							
1412			P	SG		56,210,192	14,627,372	56,210,192	14,627,372
1413					B8	56,210,192	14,627,372	56,210,192	14,627,372
1414									
1415									
1416	**Total Steam Production Plant**				**B8**	**7,320,267,032**	**1,904,926,193**	**6,866,740,006**	**1,786,906,522**
1417									
1418									
1419	Summary of Steam Production Plant by Factor								
1420		S				-	-	-	-
1421		DGP				-	-	-	-
1422		DGU				-	-	-	-
1423		SG				7,320,267,032	1,904,926,193	6,866,740,006	1,786,906,522
1424		SSGCH				-	-	-	-
1425	Total Steam Production Plant by Factor					7,320,267,032	1,904,926,193	6,866,740,006	1,786,906,522
1426	320	Land and Land Rights							
1427			P	SG		-	-	-	-
1428			P	SG		-	-	-	-
1429					B8	-	-	-	-
1430									
1431	321	Structures and Improvements							
1432			P	SG		-	-	-	-
1433			P	SG	B8	-	-	-	-
1434						-	-	-	-
1435									
1436	322	Reactor Plant Equipment							
1437			P	SG		-	-	-	-
1438			P	SG		-	-	-	-
1439					B8	-	-	-	-
1440									
1441	323	Turbogenerator Units							
1442			P	SG		-	-	-	-
1443			P	SG		-	-	-	-
1444					B8	-	-	-	-
1445									
1446	324	Land and Land Rights							
1447			P	SG		-	-	-	-
1448			P	SG		-	-	-	-
1449					B8	-	-	-	-
1450									
1451	325	Misc. Power Plant Equipment							
1452			P	SG		-	-	-	-
1453			P	SG		-	-	-	-
1454					B8	-	-	-	-
1455									
1456									
1457	NP	Unclassified Nuclear Plant - Acct 300							
1458			P	SG		-	-	-	-
1459					B8	-	-	-	-
1460									
1461									
1462	**Total Nuclear Production Plant**				**B8**	**-**	**-**	**-**	**-**
1463									
1464									
1465									
1466	Summary of Nuclear Production Plant by Factor								
1467		DGP				-	-	-	-
1468		DGU				-	-	-	-
1469		SG				-	-	-	-
1470									
1471	Total Nuclear Plant by Factor					-	-	-	-
1472									
1473	330	Land and Land Rights							
1474			P	SG		10,332,372	2,688,755	10,332,372	2,688,755
1475			P	SG		5,268,322	1,370,956	5,268,322	1,370,956
1476			P	SG		19,440,549	5,058,943	19,440,549	5,058,943
1477			P	SG		1,278,861	332,793	1,278,861	332,793
1478					B8	36,320,104	9,451,447	36,320,104	9,451,447
1479									
1480	331	Structures and Improvements							
1481			P	SG		19,715,170	5,130,406	19,715,170	5,130,406
1482			P	SG		4,896,038	1,274,078	4,896,038	1,274,078
1483			P	SG		241,524,977	62,851,157	241,524,977	62,851,157
1484			P	SG		12,056,480	3,137,413	12,056,480	3,137,413
1485					B8	278,192,664	72,393,055	278,192,664	72,393,055

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	 OREGON
1486									
1487	332	Reservoirs, Dams & Waterways							
1488			P	SG		145,549,115	37,875,711	145,549,115	37,875,711
1489			P	SG		18,827,062	4,899,297	18,827,062	4,899,297
1490			P	SG		269,730,914	70,191,085	337,775,161	87,897,989
1491			P	SG		76,753,070	19,973,169	91,687,595	23,859,526
1492			0	SG		-	-	(30,273,855)	(7,878,054)
1493					B8	510,860,161	132,939,263	563,565,078	146,654,469
1494									
1495	333	Water Wheel, Turbines, & Generators							
1496			P	SG		28,896,674	7,519,675	28,896,674	7,519,675
1497			P	SG		7,509,110	1,954,068	7,509,110	1,954,068
1498			P	SG		64,147,858	16,692,961	64,147,858	16,692,961
1499			P	SG		38,559,755	10,034,263	38,559,755	10,034,263
1500					B8	139,113,397	36,200,968	139,113,397	36,200,968
1501									
1502	334	Accessory Electric Equipment							
1503			P	SG		3,692,063	960,772	3,692,063	960,772
1504			P	SG		3,374,907	878,240	3,374,907	878,240
1505			P	SG		67,020,116	17,440,399	67,020,116	17,440,399
1506			P	SG		10,835,756	2,819,749	10,835,756	2,819,749
1507					B8	84,922,843	22,099,159	84,922,843	22,099,159
1508									
1509									
1510									
1511	335	Misc. Power Plant Equipment							
1512			P	SG		1,129,697	293,977	1,129,697	293,977
1513			P	SG		154,522	40,211	154,522	40,211
1514			P	SG		1,165,880	303,393	1,165,880	303,393
1515			P	SG		18,279	4,757	18,279	4,757
1516					B8	2,468,378	642,337	2,468,378	642,337
1517									
1518	336	Roads, Railroads & Bridges							
1519			P	SG		4,370,270	1,137,259	4,370,270	1,137,259
1520			P	SG		765,090	199,097	765,090	199,097
1521			P	SG		18,375,816	4,781,871	18,375,816	4,781,871
1522			P	SG		1,450,471	377,451	1,450,471	377,451
1523					B8	24,961,647	6,495,678	24,961,647	6,495,678
1524									
1525	337	Hydro Plant ARO							
1526			P	S		-	-	-	-
1527					B8	-	-	-	-
1528									
1529	HP	Unclassified Hydro Plant - Acct 300							
1530			P	S		-	-	-	-
1531			P	SG		-	-	-	-
1532			P	SG		-	-	-	-
1533			P	SG		-	-	-	-
1534					B8	-	-	-	-
1535									
1536	**Total Hydraulic Production Plant**				**B8**	**1,076,839,193**	**280,221,907**	**1,129,544,110**	**293,937,113**
1537									
1538	Summary of Hydraulic Plant by Factor								
1539		S				-	-	-	-
1540		SG				1,076,839,193	280,221,907	1,129,544,110	293,937,113
1541		DGP				-	-	-	-
1542		DGU				-	-	-	-
1543	Total Hydraulic Plant by Factor					1,076,839,193	280,221,907	1,129,544,110	293,937,113
1544									
1545	340	Land and Land Rights							
1546			P	S		74,986	74,986	74,986	74,986
1547			P	SG		39,022,504	10,154,683	39,022,504	10,154,683
1548			P	SG		6,100,269	1,587,451	6,100,269	1,587,451
1549			P	SG		235,129	61,187	235,129	61,187
1550					B8	45,432,889	11,878,306	45,432,889	11,878,306
1551									
1552	341	Structures and Improvements							
1553			P	SG		170,247,300	44,302,829	166,769,047	43,397,696
1554			P	SG		-	-	-	-
1555			P	SG		53,823,433	14,006,274	53,823,433	14,006,274
1556			P	SG		4,273,000	1,111,947	4,273,000	1,111,947
1557					B8	228,343,732	59,421,051	224,865,480	58,515,918
1558									
1559	342	Fuel Holders, Producers & Accessories							
1560			P	SG		13,428,889	3,494,550	13,428,889	3,494,550
1561			P	SG		-	-	-	-
1562			P	SG		2,759,334	718,051	2,759,334	718,051
1563					B8	16,188,223	4,212,602	16,188,223	4,212,602

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Line	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
1564									
1565	343	Prime Movers							
1566			P	S		-	-	129,823	129,823
1567			P	SG		-	-	-	-
1568			P	SG		1,792,108,861	466,353,904	1,003,136,418	261,042,504
1569			P	SG		1,074,511,952	279,616,297	3,228,418,965	840,119,605
1570			P	SG		57,923,631	15,073,254	57,923,631	15,073,254
1571					B8	2,924,544,444	761,043,455	4,289,608,838	1,116,365,187
1572									
1573	344	Generators							
1574			P	S		-	-	-	-
1575			P	SG		56,865,366	14,797,865	56,865,366	14,797,865
1576			P	SG		400,761,809	104,288,773	394,911,436	102,766,352
1577			P	SG		17,782,763	4,627,543	17,782,763	4,627,543
1578					B8	475,409,937	123,714,181	469,559,564	122,191,760
1579									
1580	345	Accessory Electric Plant							
1581			P	SG		211,261,475	54,975,797	198,936,993	51,768,643
1582			P	SG		113,374,163	29,502,942	113,374,163	29,502,942
1583			P	SG		-	-	-	-
1584			P	SG		2,901,493	755,045	2,901,493	755,045
1585					B8	327,537,131	85,233,784	315,212,649	82,026,629
1586									
1587									
1588									
1589	346	Misc. Power Plant Equipment							
1590			P	SG		12,586,673	3,275,384	11,927,176	3,103,765
1591			P	SG		3,337,649	868,544	3,337,649	868,544
1592			P	SG		-	-	-	-
1593					B8	15,924,321	4,143,928	15,264,824	3,972,309
1594									
1595	347	Other Production ARO							
1596			P	S		-	-	-	-
1597					B8	-	-	-	-
1598									
1599	OP	Unclassified Other Prod Plant-Acct 300							
1600			P	S		-	-	-	-
1601			P	SG		(553,173)	(143,950)	(553,173)	(143,950)
1602						(553,173)	(143,950)	(553,173)	(143,950)
1603									
1604	**Total Other Production Plant**				**B8**	**4,032,827,505**	**1,049,503,356**	**5,375,579,294**	**1,399,018,761**
1605									
1606	Summary of Other Production Plant by Factor								
1607		S				74,986	74,986	204,809	204,809
1608		DGU				-	-	-	-
1609		SG				4,032,752,519	1,049,428,371	5,375,374,484	1,398,813,952
1610		SSGCT				-	-	-	-
1611	Total of Other Production Plant by Factor					4,032,827,505	1,049,503,356	5,375,579,294	1,399,018,761
1612									
1613	Experimental Plant								
1614	103	Experimental Plant							
1615			P	SG		-	-	-	-
1616	**Total Experimental Production Plant**				**B8**	**-**	**-**	**-**	**-**
1617									
1618	**Total Production Plant**				**B8**	**12,429,933,730**	**3,234,651,456**	**13,371,863,410**	**3,479,862,396**
1619	350	Land and Land Rights							
1620			T	SG		21,061,510	5,480,759	21,061,510	5,480,759
1621			T	SG		48,203,820	12,543,903	48,203,820	12,543,903
1622			T	SG		202,173,533	52,610,876	202,173,533	52,610,876
1623					B8	271,438,863	70,635,538	271,438,863	70,635,538
1624									
1625	352	Structures and Improvements							
1626			T	S		-	-	-	-
1627			T	SG		7,026,134	1,828,385	7,026,134	1,828,385
1628			T	SG		17,682,315	4,601,404	17,682,315	4,601,404
1629			T	SG		253,240,919	65,899,954	253,240,919	65,899,954
1630					B8	277,949,368	72,329,743	277,949,368	72,329,743
1631									
1632	353	Station Equipment							
1633			T	SG		106,317,064	27,666,499	106,317,064	27,666,499
1634			T	SG		154,018,190	40,079,588	154,018,190	40,079,588
1635			T	SG		1,938,735,944	504,510,131	1,938,735,944	504,510,131
1636					B8	2,199,071,199	572,256,218	2,199,071,199	572,256,218
1637									
1638	354	Towers and Fixtures							
1639			T	SG		128,108,873	33,337,301	128,108,873	33,337,301
1640			T	SG		131,291,848	34,165,595	131,291,848	34,165,595
1641			T	SG		1,044,149,057	271,715,073	1,044,149,057	271,715,073
1642					B8	1,303,549,778	339,217,969	1,303,549,778	339,217,969
1643									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
1644	355	Poles and Fixtures							
1645			T	SG		61,226,901	15,932,852	61,226,901	15,932,852
1646			T	SG		114,992,728	29,924,135	114,992,728	29,924,135
1647			T	SG		815,456,440	212,203,233	1,950,738,887	507,633,613
1648					B8	991,676,069	258,060,220	2,126,958,517	553,490,600
1649									
1650	356	Clearing and Grading							
1651			T	SG		158,450,690	41,233,041	158,450,690	41,233,041
1652			T	SG		157,758,213	41,052,840	157,758,213	41,052,840
1653			T	SG		954,283,677	248,329,735	954,283,677	248,329,735
1654					B8	1,270,492,579	330,615,616	1,270,492,579	330,615,616
1655									
1656	357	Underground Conduit							
1657			T	SG		6,371	1,658	6,371	1,658
1658			T	SG		91,651	23,850	91,651	23,850
1659			T	SG		3,689,299	960,053	3,689,299	960,053
1660					B8	3,787,321	985,561	3,787,321	985,561
1661									
1662	358	Underground Conductors							
1663			T	SG		-	-	-	-
1664			T	SG		1,087,552	283,010	1,087,552	283,010
1665			T	SG		6,947,802	1,808,001	6,947,802	1,808,001
1666					B8	8,035,354	2,091,011	8,035,354	2,091,011
1667									
1668	359	Roads and Trails							
1669			T	SG		1,863,032	484,810	1,863,032	484,810
1670			T	SG		440,513	114,633	440,513	114,633
1671			T	SG		9,633,656	2,506,931	9,633,656	2,506,931
1672					B8	11,937,200	3,106,374	11,937,200	3,106,374
1673									
1674	TP	Unclassified Trans Plant - Acct 300							
1675			T	SG		108,436,132	28,217,936	108,436,132	28,217,936
1676					B8	108,436,132	28,217,936	108,436,132	28,217,936
1677									
1678	TS0	Unclassified Trans Sub Plant - Acct 300							
1679			T	SG		-	-	-	-
1680					B8	-	-	-	-
1681									
1682	**Total Transmission Plant**				**B8**	**6,446,373,863**	**1,677,516,185**	**7,581,656,310**	**1,972,946,565**
1683	Summary of Transmission Plant by Factor								
1684			DGP			-	-	-	-
1685			DGU			-	-	-	-
1686			SG			6,446,373,863	1,677,516,185	7,581,656,310	1,972,946,565
1687	Total Transmission Plant by Factor					6,446,373,863	1,677,516,185	7,581,656,310	1,972,946,565
1688	360	Land and Land Rights							
1689			DPW	S		63,752,760	14,190,626	68,285,023	15,425,674
1690					B8	63,752,760	14,190,626	68,285,023	15,425,674
1691									
1692	361	Structures and Improvements							
1693			DPW	S		122,141,315	32,577,502	130,824,493	34,943,680
1694					B8	122,141,315	32,577,502	130,824,493	34,943,680
1695									
1696	362	Station Equipment							
1697			DPW	S		1,025,529,740	258,312,285	1,098,435,924	278,179,324
1698					B8	1,025,529,740	258,312,285	1,098,435,924	278,179,324
1699									
1700	363	Storage Battery Equipment							
1701			DPW	S		-	-	-	-
1702					B8	-	-	-	-
1703									
1704	364	Poles, Towers & Fixtures							
1705			DPW	S		1,234,275,701	395,746,642	1,322,021,896	419,657,606
1706					B8	1,234,275,701	395,746,642	1,322,021,896	419,657,606
1707									
1708	365	Overhead Conductors							
1709			DPW	S		785,199,742	272,505,215	841,020,569	287,716,469
1710					B8	785,199,742	272,505,215	841,020,569	287,716,469
1711									
1712	366	Underground Conduit							
1713			DPW	S		389,442,059	97,778,526	417,127,980	105,322,979
1714					B8	389,442,059	97,778,526	417,127,980	105,322,979
1715									
1716									
1717									
1718									
1719	367	Underground Conductors							
1720			DPW	S		909,201,308	190,342,123	973,837,560	207,955,594
1721					B8	909,201,308	190,342,123	973,837,560	207,955,594

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
368	Line Transformers							
		DPW	S		1,400,334,104	460,558,670	1,499,885,597	487,686,594
				B8	1,400,334,104	460,558,670	1,499,885,597	487,686,594
369	Services							
		DPW	S		838,536,076	298,209,521	898,148,649	314,454,032
				B8	838,536,076	298,209,521	898,148,649	314,454,032
370	Meters							
		DPW	S		237,285,260	91,508,919	254,154,164	96,105,719
				B8	237,285,260	91,508,919	254,154,164	96,105,719
371	Installations on Customers' Premises							
		DPW	S		8,805,090	2,639,353	9,431,055	2,809,929
				B8	8,805,090	2,639,353	9,431,055	2,809,929
372	Leased Property							
		DPW	S		-	-	-	-
				B8	-	-	-	-
373	Street Lights							
		DPW	S		62,662,687	24,072,918	67,117,455	25,286,848
				B8	62,662,687	24,072,918	67,117,455	25,286,848
DP	Unclassified Dist Plant - Acct 300							
		DPW	S		61,420,721	15,304,313	61,420,721	15,304,313
				B8	61,420,721	15,304,313	61,420,721	15,304,313
DS0	Unclassified Dist Sub Plant - Acct 300							
		DPW	S		-	-	-	-
				B8	-	-	-	-
Total Distribution Plant				**B8**	**7,138,586,565**	**2,153,746,612**	**7,641,711,087**	**2,290,848,762**
Summary of Distribution Plant by Factor								
	S				7,138,586,565	2,153,746,612	7,641,711,087	2,290,848,762
Total Distribution Plant by Factor					7,138,586,565	2,153,746,612	7,641,711,087	2,290,848,762
389	Land and Land Rights							
		G-SITUS	S		14,969,289	6,114,113	14,969,289	6,114,113
		CUST	CN		1,128,506	352,286	1,128,506	352,286
		G-DGU	SG		332	86	332	86
		G-SG	SG		1,228	319	1,228	319
		PTD	SO		7,516,302	2,045,585	7,516,302	2,045,585
				B8	23,615,657	8,512,391	23,615,657	8,512,391
390	Structures and Improvements							
		G-SITUS	S		132,298,513	39,510,644	132,298,513	39,510,644
		G-DGP	SG		335,238	87,238	335,238	87,238
		G-DGU	SG		1,487,359	387,050	1,487,359	387,050
		CUST	CN		8,207,715	2,562,207	8,207,715	2,562,207
		G-SG	SG		5,786,797	1,505,877	5,786,797	1,505,877
		P	SE		1,235,588	310,151	1,235,588	310,151
		PTD	SO		96,548,451	26,275,962	96,548,451	26,275,962
				B8	245,899,661	70,639,129	245,899,661	70,639,129
391	Office Furniture & Equipment							
		G-SITUS	S		6,522,746	2,191,143	6,522,746	2,191,143
		G-DGP	SG		-	-	-	-
		G-DGU	SG		-	-	-	-
		CUST	CN		4,040,675	1,261,380	4,040,675	1,261,380
		G-SG	SG		3,183,296	828,377	3,183,296	828,377
		P	SE		10,034	2,519	10,034	2,519
		PTD	SO		51,456,014	14,003,915	51,456,014	14,003,915
		G-SG	SG		-	-	-	-
		G-SG	SG		4,039	1,051	4,039	1,051
				B8	65,216,804	18,288,385	65,216,804	18,288,385

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
1791									
1792	392	Transportation Equipment							
1793			G-SITUS	S		88,138,177	24,809,266	88,138,177	24,809,266
1794			PTD	SO		6,893,825	1,876,176	6,893,825	1,876,176
1795			G-SG	SG		21,029,810	5,472,510	21,029,810	5,472,510
1796			CUST	CN		-	-	-	-
1797			G-DGU	SG		455,094	118,427	455,094	118,427
1798			P	SE		488,092	122,518	488,092	122,518
1799			G-DGP	SG		70,616	18,376	70,616	18,376
1800			G-SG	SG		299,519	77,943	299,519	77,943
1801			G-DGU	SG		44,655	11,620	44,655	11,620
1802					B8	117,419,788	32,506,837	117,419,788	32,506,837
1803									
1804	393	Stores Equipment							
1805			G-SITUS	S		8,440,223	2,635,106	8,440,223	2,635,106
1806			G-DGP	SG		-	-	-	-
1807			G-DGU	SG		-	-	-	-
1808			PTD	SO		255,085	69,422	255,085	69,422
1809			G-SG	SG		5,860,195	1,524,977	5,860,195	1,524,977
1810			G-DGU	SG		53,971	14,045	53,971	14,045
1811					B8	14,609,473	4,243,550	14,609,473	4,243,550
1812									
1813	394	Tools, Shop & Garage Equipment							
1814			G-SITUS	S		34,364,049	10,475,442	34,364,049	10,475,442
1815			G-DGP	SG		93,384	24,301	93,384	24,301
1816			G-SG	SG		22,341,758	5,813,914	22,341,758	5,813,914
1817			PTD	SO		2,127,184	578,920	2,127,184	578,920
1818			P	SE		109,044	27,372	109,044	27,372
1819			G-DGU	SG		-	-	-	-
1820			G-SG	SG		1,716,843	446,768	1,716,843	446,768
1821			G-SG	SG		89,913	23,398	89,913	23,398
1822					B8	60,842,175	17,390,114	60,842,175	17,390,114
1823									
1824	395	Laboratory Equipment							
1825			G-SITUS	S		21,189,900	7,887,804	21,189,900	7,887,804
1826			G-DGP	SG		-	-	-	-
1827			G-DGU	SG		-	-	-	-
1828			PTD	SO		4,973,535	1,353,563	4,973,535	1,353,563
1829			P	SE		1,257,984	315,773	1,257,984	315,773
1830			G-SG	SG		6,377,729	1,659,653	6,377,729	1,659,653
1831			G-SG	SG		223,587	58,183	223,587	58,183
1832			G-SG	SG		14,022	3,649	14,022	3,649
1833					B8	34,036,757	11,278,624	34,036,757	11,278,624
1834									
1835	396	Power Operated Equipment							
1836			G-SITUS	S		136,639,519	40,611,944	136,639,519	40,611,944
1837			G-DGP	SG		262,000	68,179	262,000	68,179
1838			G-SG	SG		43,994,098	11,448,423	43,994,098	11,448,423
1839			PTD	SO		6,093,193	1,658,281	6,093,193	1,658,281
1840			G-DGU	SG		1,057,504	275,190	1,057,504	275,190
1841			P	SE		236,686	59,412	236,686	59,412
1842			P	SG		-	-	-	-
1843			G-SG	SG		1,378,336	358,679	1,378,336	358,679
1844					B8	189,661,336	54,480,108	189,661,336	54,480,108
1845	397	Communication Equipment							
1846			G-SITUS	S		203,501,421	76,477,521	278,077,094	94,814,269
1847			G-DGP	SG		412,544	107,355	412,544	107,355
1848			G-DGU	SG		1,136,750	295,812	1,136,750	295,812
1849			PTD	SO		93,060,474	25,326,699	111,249,949	30,277,021
1850			CUST	CN		3,848,526	1,201,397	1,036,506	323,567
1851			G-SG	SG		175,128,628	45,573,079	186,276,393	48,474,021
1852			P	SE		341,558	85,736	289,707	72,721
1853			G-SG	SG		1,285,815	334,603	1,285,815	334,603
1854			G-SG	SG		16,633	4,328	16,633	4,328
1855					B8	478,732,348	149,406,530	579,781,391	174,703,697
1856									
1857	398	Misc. Equipment							
1858			G-SITUS	S		2,966,638	1,107,524	2,966,638	1,107,524
1859			G-DGP	SG		-	-	-	-
1860			G-DGU	SG		-	-	-	-
1861			CUST	CN		82,497	25,753	82,497	25,753
1862			PTD	SO		2,205,144	600,137	2,205,144	600,137
1863			P	SE		3,966	995	3,966	995
1864			G-SG	SG		2,713,930	706,236	2,713,930	706,236
1865			G-SG	SG		-	-	-	-
1866					B8	7,972,175	2,440,646	7,972,175	2,440,646

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
399	Coal Mine							
		P	SE		1,854,828	465,589	84,739,827	21,270,957
MP		P	SE		-	-	-	-
				B8	1,854,828	465,589	84,739,827	21,270,957
399L	WIDCO Capital Lease							
		P	SE		-	-	-	-
					-	-	-	-
	Remove Capital Leases				-	-	-	-
					-	-	-	-
1011390	General Capital Leases							
		G-SITUS	S		6,010,764	2,257,880	6,010,764	2,257,880
		P	SG		11,703,570	3,045,577	11,703,570	3,045,577
		PTD	SO		1,887,427	513,669	1,887,427	513,669
				B9	19,601,761	5,817,126	19,601,761	5,817,126
	Remove Capital Leases				(19,601,761)	(5,817,126)	(19,601,761)	(5,817,126)
					-	-	-	-
1011346	General Gas Line Capital Leases							
		P	SG		-	-	-	-
				B9	-	-	-	-
	Remove Capital Leases				-	-	-	-
					-	-	-	-
GP	Unclassified Gen Plant - Acct 300							
		G-SITUS	S		-	-	-	-
		PTD	SO		39,436,687	10,732,817	39,436,687	10,732,817
		CUST	CN		-	-	-	-
		G-SG	SG		-	-	-	-
		G-DGP	SG		-	-	-	-
		G-DGU	SG		-	-	-	-
				B8	39,436,687	10,732,817	39,436,687	10,732,817
399G	Unclassified Gen Plant - Acct 300							
		G-SITUS	S		-	-	-	-
		PTD	SO		-	-	-	-
		G-SG	SG		-	-	-	-
		G-DGP	SG		-	-	-	-
		G-DGU	SG		-	-	-	-
				B8	-	-	-	-
Total General Plant				**B8**	**1,279,297,689**	**380,384,721**	**1,463,231,730**	**426,487,256**
Summary of General Plant by Factor								
	S				655,041,239	214,078,386	729,616,912	232,415,134
	DGP				-	-	-	-
	DGU				-	-	-	-
	SG				308,559,192	80,295,225	319,706,957	83,196,167
	SO				312,453,319	85,035,147	330,642,794	89,985,469
	SE				5,537,780	1,390,065	88,370,928	22,182,418
	CN				17,307,919	5,403,023	14,495,900	4,525,194
	DEU				-	-	-	-
	SSGCT				-	-	-	-
	SSGCH				-	-	-	-
	Less Capital Leases				(19,601,761)	(5,817,126)	(19,601,761)	(5,817,126)
Total General Plant by Factor					1,279,297,689	380,384,721	1,463,231,730	426,487,256
301	Organization							
		I-SITUS	S		-	-	-	-
		PTD	SO		-	-	-	-
		I-SG	SG		-	-	-	-
				B8	-	-	-	-
302	Franchise & Consent							
		I-SITUS	S		(31,081,215)	-	(31,081,215)	-
		I-SG	SG		10,337,588	2,690,113	4,228,422	1,100,347
		I-SG	SG		175,244,590	45,603,256	175,004,296	45,540,725
		I-SG	SG		9,350,399	2,433,220	9,350,399	2,433,220
		I-DGP	SG		-	-	-	-
		I-DGU	SG		600,993	156,394	600,993	156,394
				B8	164,452,355	50,882,982	158,102,895	49,230,686

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	 OREGON
1941									
1942	303	Miscellaneous Intangible Plant							
1943			I-SITUS	S		22,022,344	4,615,241	23,265,327	5,489,081
1944			I-SG	SG		167,592,259	43,611,918	171,592,259	44,652,823
1945			PTD	SO		385,727,443	104,976,929	403,194,225	109,730,568
1946			P	SE		-	-	(1,106,269)	(277,690)
1947			CUST	CN		176,107,084	54,975,452	175,494,022	54,784,072
1948			P	SG		-	-	-	-
1949			I-DGP	SG		-	-	-	-
1950					B8	751,449,130	208,179,539	772,439,565	214,378,854
1951	303	Less Non-Regulated Plant							
1952			I-SITUS	S		-	-	-	-
1953						751,449,130	208,179,539	772,439,565	214,378,854
1954	IP	Unclassified Intangible Plant - Acct 300							
1955			I-SITUS	S		-	-	-	-
1956			I-SG	SG		-	-	-	-
1957			I-DGU	SG		-	-	-	-
1958			PTD	SO		-	-	-	-
1959						-	-	-	-
1960									
1961	**Total Intangible Plant**				**B8**	**915,901,485**	**259,062,522**	**930,542,460**	**263,609,540**
1962									
1963	Summary of Intangible Plant by Factor								
1964		S				(9,058,871)	4,615,241	(7,815,888)	5,489,081
1965		DGP				-	-	-	-
1966		DGU				-	-	-	-
1967		SG				363,125,829	94,494,900	360,776,369	93,883,509
1968		SO				385,727,443	104,976,929	403,194,225	109,730,568
1969		CN				176,107,084	54,975,452	175,494,022	54,784,072
1970		SSGCT				-	-	-	-
1971		SSGCH				-	-	-	-
1972		SE				-	-	(1,106,269)	(277,690)
1973	Total Intangible Plant by Factor					915,901,485	259,062,522	930,542,460	263,609,540
1974	Summary of Unclassified Plant (Account 106)								
1975		DP				61,420,721	15,304,313	61,420,721	15,304,313
1976		DS0				-	-	-	-
1977		GP				39,436,687	10,732,817	39,436,687	10,732,817
1978		HP				-	-	-	-
1979		NP				-	-	-	-
1980		OP				(553,173)	(143,950)	(553,173)	(143,950)
1981		TP				108,436,132	28,217,936	108,436,132	28,217,936
1982		TS0				-	-	-	-
1983		IP				-	-	-	-
1984		MP				-	-	-	-
1985		SP				56,210,192	14,627,372	56,210,192	14,627,372
1986	Total Unclassified Plant by Factor					264,950,558	68,738,488	264,950,558	68,738,488
1987									
1988	**Total Electric Plant In Service**				**B8**	**28,210,093,332**	**7,705,361,496**	**30,989,004,997**	**8,433,754,519**
1989	Summary of Electric Plant by Factor								
1990		S				7,784,643,920	2,372,515,226	8,363,716,920	2,528,957,787
1991		SE				5,537,780	1,390,065	87,264,660	21,904,728
1992		DGU				-	-	-	-
1993		DGP				-	-	-	-
1994		SG				19,547,917,628	5,086,882,780	21,633,798,237	5,629,683,827
1995		SO				698,180,762	190,012,076	733,837,020	199,716,037
1996		CN				193,415,003	60,378,475	189,989,922	59,309,266
1997		DEU				-	-	-	-
1998		SSGCH				-	-	-	-
1999		SSGCT				-	-	-	-
2000		Less Capital Leases				(19,601,761)	(5,817,126)	(19,601,761)	(5,817,126)
2001						28,210,093,332	7,705,361,496	30,989,004,997	8,433,754,519
2002	105	Plant Held For Future Use							
2003			DPW	S		13,840,559	7,426,112	-	-
2004			P	SG		-	-	-	-
2005			T	SG		3,657,534	951,787	3,657,534	951,787
2006			P	SG		8,923,302	2,322,078	8,923,302	2,322,078
2007			P	SE		-	-	-	-
2008			G	SG		-	-	(12,580,836)	(3,273,865)
2009									
2010									
2011	**Total Plant Held For Future Use**				**B10**	**26,421,395**	**10,699,976**	**-**	**-**
2012									
2013	114	Electric Plant Acquisition Adjustments							
2014			P	S		11,763,784	-	11,763,784	-
2015			P	SG		144,704,699	37,655,972	144,704,699	37,655,972
2016			P	SG		-	-	-	-
2017	**Total Electric Plant Acquisition Adjustment**				**B15**	**156,468,483**	**37,655,972**	**156,468,483**	**37,655,972**

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
115	Accum Provision for Asset Acquisition Adjustments							
		P	S		(1,294,270)	-	(1,294,270)	-
		P	SG		(128,417,358)	(33,417,577)	(137,980,477)	(35,906,153)
		P	SG		-	-	-	-
				B15	(129,711,629)	(33,417,577)	(139,274,748)	(35,906,153)
128	Pensions							
		LABOR	SO		2,485,363	676,399	-	-
Total Pensions				**B15**	**2,485,363**	**676,399**	**-**	**-**
124	Weatherization							
		DMSC	S		795,098	0	795,098	0
		DMSC	SO		(5,008)	(1,363)	(5,008)	(1,363)
				B16	790,090	(1,363)	790,090	(1,363)
182W	Weatherization							
		DMSC	S		(9,216,048)	-	(9,216,048)	-
		DMSC	SG		-	-	-	-
		DMSC	SGCT		-	-	-	-
		DMSC	SO		-	-	-	-
				B16	(9,216,048)	-	(9,216,048)	-
186W	Weatherization							
		DMSC	S		-	-	-	-
		DMSC	CN		-	-	-	-
		DMSC	CNP		-	-	-	-
		DMSC	SG		-	-	-	-
		DMSC	SO		-	-	-	-
				B16	-	-	-	-
Total Weatherization				**B16**	**(8,425,958)**	**(1,363)**	**(8,425,958)**	**(1,363)**
151	Fuel Stock							
		P	DEU		-	-	-	-
		P	SE		174,905,762	43,903,949	161,077,156	40,432,763
		P	SE		-	-	-	-
		P	SE		14,945,408	3,751,520	14,945,408	3,751,520
				B13	189,851,170	47,655,469	176,022,564	44,184,283
152	Fuel Stock - Undistributed							
		P	SE		-	-	-	-
					-	-	-	-
25316	UAMPS Working Capital Deposit							
		P	SE		(2,479,000)	(622,266)	(2,063,462)	(517,960)
				B13	(2,479,000)	(622,266)	(2,063,462)	(517,960)
25317	DG&T Working Capital Deposit							
		P	SE		(2,622,091)	(658,184)	(2,707,856)	(679,712)
				B13	(2,622,091)	(658,184)	(2,707,856)	(679,712)
25319	Provo Working Capital Deposit							
		P	SE		-	-	-	-
					-	-	-	-
Total Fuel Stock				**B13**	**184,750,079**	**46,375,019**	**171,251,246**	**42,986,611**
154	Materials and Supplies							
		MSS	S		120,236,546	41,769,971	120,236,546	41,769,971
		MSS	SG		5,020,695	1,306,517	(1,601,510)	(416,755)
		MSS	SE		-	-	-	-
		MSS	SO		336,188	91,495	336,188	91,495
		MSS	SG		116,359,013	30,279,678	116,359,013	30,279,678
		MSS	SG		7,954	2,070	7,954	2,070
		MSS	SNPD		(1,742,112)	(466,126)	(1,742,112)	(466,126)
		MSS	SG		-	-	-	-
		MSS	SG		-	-	-	-
		MSS	SG		-	-	-	-
		MSS	SG		-	-	-	-
		MSS	SG		9,492,432	2,470,181	9,492,432	2,470,181
		MSS	SG		-	-	-	-
				B13	249,710,716	75,453,785	243,088,511	73,730,513
163	Stores Expense Undistributed							
		MSS	SO		-	-	-	-
				B13	-	-	-	-

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
2095									
2096	25318	Provo Working Capital Deposit							
2097			MSS	SG		(273,000)	(71,042)	(273,000)	(71,042)
2098									
2099					B13	(273,000)	(71,042)	(273,000)	(71,042)
2100									
2101	**Total Materials and Supplies**				**B13**	**249,437,716**	**75,382,743**	**242,815,511**	**73,659,471**
2102									
2103	165	Prepayments							
2104			DMSC	S		25,224,552	3,030,864	25,224,552	3,030,864
2105			GP	GPS		181,209	49,317	181,209	49,317
2106			PT	SG		2,258,700	587,773	2,258,700	587,773
2107			P	SE		3,590	901	3,590	901
2108			PTD	SO		18,872,344	5,136,167	18,872,344	5,136,167
2109	**Total Prepayments**				**B15**	**46,540,395**	**8,805,023**	**46,540,395**	**8,805,023**
2110									
2111	182M	Misc Regulatory Assets							
2112			DDS2	S		105,288,567	(11,751,160)	107,835,611	(9,204,116)
2113			DEFSG	SG		3,448,669	897,435	3,448,669	897,435
2114			P	SGCT		-	-	-	-
2115			DEFSG	SG-P		-	-	-	-
2116			P	SE		185,628,278	46,595,460	173,484,054	43,547,079
2117			P	SG		-	-	-	-
2118			DDSO2	SO		472,555,803	128,607,538	36,359,142	9,895,254
2119					B16	766,921,317	164,349,273	321,127,477	45,135,652
2120									
2121	186M	Misc Deferred Debits							
2122			LABOR	S		3,746,439	-	3,746,439	-
2123			P	SG		-	-	-	-
2124			P	SG		-	-	-	-
2125			DEFSG	SG		80,227,740	20,877,370	83,583,719	21,750,684
2126			LABOR	SO		164,900	44,878	164,900	44,878
2127			P	SE		1,479,125	371,282	1,479,125	371,282
2128			P	SG		-	-	-	-
2129			GP	EXCTAX		-	-	-	-
2130	**Total Misc. Deferred Debits**				**B11**	**85,618,204**	**21,293,530**	**88,974,183**	**22,166,844**
2131									
2132	Working Capital								
2133	CWC	Cash Working Capital							
2134			CWC	S		30,507,590	8,591,673	26,692,729	7,708,249
2135			CWC	SO		-	-	-	-
2136			CWC	SE		-	-	-	-
2137					B14	30,507,590	8,591,673	26,692,729	7,708,249
2138									
2139	OWC	Other Work. Cap.							
2140	131	Cash	GP	SNP		-	-	-	-
2141	135	Working Funds	GP	SG		-	-	-	-
2142	141	Notes Receivable	GP	SO		-	-	-	-
2143	143	Other A/R	GP	SO		44,856,675	12,207,884	44,856,675	12,207,884
2144	232	A/P	PTD	S		(16,765)	-	(16,765)	-
2145	232	A/P	PTD	SO		(7,127,991)	(1,939,905)	(7,127,991)	(1,939,905)
2146	232	A/P	P	SE		(1,813,806)	(455,292)	(1,813,806)	(455,292)
2147	232	A/P	T	SG		(2,053,168)	(534,288)	(2,053,168)	(534,288)
2148	2533	Other Msc. Df. Crd.	P	S		-	-	-	-
2149	2533	Other Msc. Df. Crd.	P	SE		(6,512,893)	(1,634,833)	(6,991,690)	(1,755,018)
2150	230	Asset Retir. Oblig.	P	SG		-	-	-	-
2151	230	Asset Retir. Oblig.	P	S		(8,267,790)	-	(8,267,790)	-
2152	254	Decom. Reg Liability	P	SG		-	-	(20,444,814)	(5,320,279)
2153	254	Reclam. Reg Liability	P	SE		-	-	(7,249,448)	(1,819,719)
2154	2533	Cholla Reclamation	P	SE		-	-	-	-
2155					B14	19,064,261	7,643,565	(9,108,797)	383,382
2156									
2157	**Total Working Capital**				**B14**	**49,571,851**	**16,235,238**	**17,583,931**	**8,091,631**
2158	Miscellaneous Rate Base								
2159	18221	Unrec Plant & Reg Study Costs							
2160			P	S		-	-	-	-
2161									
2162						-	-	-	-
2163									
2164	18222	Nuclear Plant - Trojan							
2165			P	S		-	-	-	-
2166			P	TROJP		-	-	-	-
2167			P	TROJD		-	-	-	-
2168					B16	-	-	-	-

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	OREGON
1869	Misc Deferred Debits-Trojan							
		P	S		-	-	-	-
		P	SG		-	-	-	-
					-	-	-	-
Total Miscellaneous Rate Base				**B15**	**-**	**-**	**-**	**-**
Total Rate Base Additions					**1,430,077,216**	**348,054,234**	**897,060,521**	**202,593,689**
235	Customer Service Deposits							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
Total Customer Service Deposits				B15	**-**	**-**	**-**	**-**
2281	Prop Ins	PTD	S		(8,955,526)	11,606,109	(8,955,526)	11,606,109
2282	Inj & Dam	PTD	SO		(16,281,344)	(4,431,019)	(16,281,344)	(4,431,019)
2283	Pen & Ben	PTD	SO		(100,000,003)	(27,215,313)	(1,650,782)	(449,265)
2282	Prov for Injurie	PTD	S		(8,767,623)	(8,767,623)	(8,767,623)	(8,767,623)
25335	Reg Liabilities	PTD	SE		(115,119,099)	(28,896,607)	(115,119,099)	(28,896,607)
				B15	(249,123,595)	(57,704,452)	(150,774,374)	(30,938,405)
22841	Accum Misc. Operating Provisions							
		P	S		-	-	-	-
		P	SG		(512,398)	(133,339)	(512,398)	(133,339)
				B15	(512,398)	(133,339)	(512,398)	(133,339)
254105	ARO	P	S		258,730	-	258,730	-
230	ARO	P	TROJD		(2,743,652)	(709,453)	(2,743,652)	(709,453)
254105	ARO	P	TROJD		(2,639,042)	(682,403)	(2,639,042)	(682,403)
254		P	S		(308,256,823)	(30,478,104)	(616,204,284)	(388,516,991)
				B15	(313,380,787)	(31,869,961)	(621,328,249)	(389,908,847)
252	Customer Advances for Construction							
		DPW	S		(2,462,507)	(919,079)	(18,762,474)	(2,640,295)
		DPW	SE		-	-	-	-
		T	SG		(59,193,503)	(15,403,708)	(42,893,536)	(11,162,027)
		DPW	SO		-	-	-	-
		CUST	CN		-	-	-	-
Total Customer Advances for Construction				**B20**	**(61,656,010)**	**(16,322,786)**	**(61,656,010)**	**(13,802,322)**
25398	SO2 Emissions							
		P	SE		-	-	-	-
					-	-	-	-
25399	Other Deferred Credits							
		P	S		(322,520)	(150,115)	(322,520)	(150,115)
		LABOR	SO		(58,098,162)	(15,811,596)	(58,098,162)	(15,811,596)
		P	SG		(26,308,326)	(6,846,119)	(26,308,326)	(6,846,119)
		P	SE		(7,538,284)	(1,892,222)	(7,538,284)	(1,892,222)
				B15	(92,267,292)	(24,700,051)	(92,267,292)	(24,700,051)
190	Accumulated Deferred Income Taxes							
		P	S		79,883,162	9,583,796	191,671,189	100,469,432
		CUST	CN		-	-	-	-
		LABOR	SO		110,574,221	30,093,120	76,650,267	20,860,610
		P	DGP		-	-	-	-
		IBT	IBT		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		CUST	BADDEBT		2,719,261	969,741	2,754,659	982,365
		P	TROJD		1,323,421	342,210	1,314,030	339,782
		P	SG		26,606,986	6,923,838	6,475,875	1,685,193
		P	SE		21,618,853	5,426,654	(4,085,884)	(1,025,618)
		PTD	SNP		-	-	-	-
		DPW	SNPD		794,940	212,697	1,932,611	517,097
		P	SG		-	-	-	-
				B19	243,520,844	53,552,056	276,712,747	123,828,861
281	Accumulated Deferred Income Taxes							
		P	S		-	-	-	-
		PT	SG		(177,049,368)	(46,072,906)	0	0
		T	SG		-	-	-	-
				B19	(177,049,368)	(46,072,906)	0	0

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
282	Accumulated Deferred Income Taxes							
		GP	S		(170,620,898)	(93,279,909)	(2,851,252,073)	(686,948,122)
		ACCMDIT	DITBAL		(3,983,914,217)	(983,169,895)	(383,928)	(94,748)
		PT	SNP		-	-	-	-
		LABOR	SO		(1,047,616)	(285,112)	(1,094,899)	(297,980)
		PTD	GPS		-	-	-	-
		DPW	CIAC		-	-	-	-
		P	SNPD		-	-	-	-
		GP	SCHMDEXP		-	-	-	-
		TAXDEPR	TAXDEPR		-	-	-	-
		P	SG		-	-	-	-
		PT	IBT		-	-	-	-
		PT	SG		-	-	-	-
		P	CN		-	-	569	178
		P	SE		(6,997,593)	(1,756,500)	(2,438,337)	(612,059)
		P	SG		(841,696)	(219,032)	(56,847,014)	(14,793,089)
				B19	(4,163,422,021)	(1,078,710,448)	(2,912,015,682)	(702,745,820)
283	Accumulated Deferred Income Taxes							
		GP	S		(31,598,310)	(1,660,055)	(79,285,404)	(857,569)
		P	SG		(1,699,725)	(442,313)	(1,437,450)	(374,062)
		P	SE		(42,271,091)	(10,610,673)	(14,979,435)	(3,760,061)
		LABOR	SO		(131,569,480)	(35,807,045)	(21,498,251)	(5,850,816)
		GP	GPS		(6,689,945)	(1,820,689)	(6,821,149)	(1,856,397)
		PTD	SNP		(1,047,982)	(275,536)	(764,589)	(201,026)
		P	TROJD		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B19	(214,876,533)	(50,616,311)	(124,786,278)	(12,899,931)
Total Accum Deferred Income Tax				**B19**	**(4,311,827,079)**	**(1,121,847,609)**	**(2,760,089,212)**	**(591,816,891)**
255	Accumulated Investment Tax Credit							
		PTD	S		(38,436)	-	0	-
		PTD	ITC84		-	-	-	-
		PTD	ITC85		-	-	-	-
		PTD	ITC86		-	-	-	-
		PTD	ITC88		-	-	-	-
		PTD	ITC89		-	-	-	-
		PTD	ITC90		(42,534)	(6,778)	-	-
		PTD	SG		(216,528)	(56,346)	0	0
Total Accumulated ITC				**B19**	**(297,497)**	**(63,124)**	**1**	**0**
Total Rate Base Deductions					**(5,029,064,657)**	**(1,252,641,323)**	**(3,686,627,534)**	**(1,051,299,856)**
108SP	Steam Prod Plant Accumulated Depr							
		P	S		10,702,263	-	10,702,263	-
		P	SG		(759,016,718)	(197,516,132)	(759,016,718)	(197,516,132)
		P	SG		(726,882,090)	(189,153,855)	(726,882,090)	(189,153,855)
		P	SG		(1,488,197,425)	(387,268,148)	(2,537,439,356)	(660,308,520)
		P	SG		-	-	-	-
		P	SG		(246,321,600)	(64,099,365)	(246,321,600)	(64,099,365)
				B17	(3,209,715,569)	(838,037,500)	(4,258,957,500)	(1,111,077,872)
108NP	Nuclear Prod Plant Accumulated Depr							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B17	-	-	-	-
108HP	Hydraulic Prod Plant Accum Depr							
		P	S		3,575,830	-	3,575,830	-
		P	SG		(175,334,101)	(45,626,549)	(175,334,101)	(45,626,549)
		P	SG		(30,353,650)	(7,898,819)	(30,353,650)	(7,898,819)
		P	SG		(189,513,434)	(49,316,384)	(251,878,803)	(65,545,495)
		P	SG		(51,987,503)	(13,528,517)	(60,901,456)	(15,848,162)
		p	SG		-	-	27,889,637	7,257,618
				B17	(443,612,856)	(116,370,269)	(487,002,542)	(127,661,407)
108OP	Other Production Plant - Accum Depr							
		P	S		-	-	(4,278)	(4,278)
		P	SG		-	-	-	-
		P	SG		(752,142,958)	(195,727,398)	376,504,462	97,976,373
		P	SG		(418,175,116)	(108,820,174)	(1,194,877,600)	(310,938,608)
		P	SG		(36,871,542)	(9,594,946)	(36,871,542)	(9,594,946)
				B17	(1,207,189,615)	(314,142,518)	(855,248,958)	(222,561,459)

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
108EP	Experimental Plant - Accum Depr							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
					-	-	-	-
Total Production Plant Accum Depreciation				**B17**	**(4,860,518,041)**	**(1,268,550,287)**	**(5,601,209,000)**	**(1,461,300,738)**
Summary of Prod Plant Depreciation by Factor								
	S				14,278,093	-	14,273,815	(4,278)
	DGP				-	-	-	-
	DGU				-	-	-	-
	SG				(4,874,796,134)	(1,268,550,287)	(5,615,482,814)	(1,461,296,460)
	SSGCH				-	-	-	-
	SSGCT				-	-	-	-
Total of Prod Plant Depreciation by Factor					(4,860,518,041)	(1,268,550,287)	(5,601,209,000)	(1,461,300,738)
108TP	Transmission Plant Accumulated Depr							
		T	SG		(351,699,893)	(91,521,571)	(351,699,893)	(91,521,571)
		T	SG		(418,414,202)	(108,882,391)	(418,414,202)	(108,882,391)
		T	SG		(1,043,195,644)	(271,466,970)	(1,193,013,954)	(310,453,638)
Total Trans Plant Accum Depreciation				**B17**	**(1,813,309,739)**	**(471,870,931)**	**(1,963,128,049)**	**(510,857,599)**
108360	Land and Land Rights							
		DPW	S		(10,233,509)	(2,963,365)	(12,048,466)	(3,447,174)
				B17	(10,233,509)	(2,963,365)	(12,048,466)	(3,447,174)
108361	Structures and Improvements							
		DPW	S		(28,147,776)	(7,888,962)	(31,624,978)	(8,815,872)
				B17	(28,147,776)	(7,888,962)	(31,624,978)	(8,815,872)
108362	Station Equipment							
		DPW	S		(291,777,869)	(83,881,742)	(320,973,354)	(91,664,314)
				B17	(291,777,869)	(83,881,742)	(320,973,354)	(91,664,314)
108363	Storage Battery Equipment							
		DPW	S		-	-	-	-
				B17	-	-	-	-
108364	Poles, Towers & Fixtures							
		DPW	S		(659,772,406)	(264,470,557)	(694,910,614)	(273,837,267)
				B17	(659,772,406)	(264,470,557)	(694,910,614)	(273,837,267)
108365	Overhead Conductors							
		DPW	S		(334,433,698)	(133,533,467)	(356,787,304)	(139,492,216)
				B17	(334,433,698)	(133,533,467)	(356,787,304)	(139,492,216)
108366	Underground Conduit							
		DPW	S		(170,989,343)	(45,983,562)	(182,076,247)	(48,938,973)
				B17	(170,989,343)	(45,983,562)	(182,076,247)	(48,938,973)
108367	Underground Conductors							
		DPW	S		(403,012,479)	(88,409,472)	(428,896,246)	(95,309,247)
				B17	(403,012,479)	(88,409,472)	(428,896,246)	(95,309,247)
108368	Line Transformers							
		DPW	S		(543,787,041)	(237,387,679)	(583,652,713)	(248,014,579)
				B17	(543,787,041)	(237,387,679)	(583,652,713)	(248,014,579)
108369	Services							
		DPW	S		(326,285,972)	(131,146,354)	(350,157,993)	(137,509,863)
				B17	(326,285,972)	(131,146,354)	(350,157,993)	(137,509,863)
108370	Meters							
		DPW	S		(77,394,282)	(9,285,875)	(84,149,482)	(11,086,593)
				B17	(77,394,282)	(9,285,875)	(84,149,482)	(11,086,593)
108371	Installations on Customers' Premises							
		DPW	S		(7,198,645)	(2,109,957)	(7,449,314)	(2,176,777)
				B17	(7,198,645)	(2,109,957)	(7,449,314)	(2,176,777)
108372	Leased Property							
		DPW	S		-	-	-	-
				B17	-	-	-	-
108373	Street Lights							
		DPW	S		(31,527,544)	(11,198,218)	(33,311,468)	(11,673,755)
				B17	(31,527,544)	(11,198,218)	(33,311,468)	(11,673,755)

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
108D00	Unclassified Dist Plant - Acct 300							
		DPW	S		-	-	-	-
				B17	-	-	-	-
108DS	Unclassified Dist Sub Plant - Acct 300							
		DPW	S		-	-	-	-
				B17	-	-	-	-
108DP	Unclassified Dist Sub Plant - Acct 300							
		DPW	S		3,574,567	1,007,451	3,574,567	1,007,451
				B17	3,574,567	1,007,451	3,574,567	1,007,451
Total Distribution Plant Accum Depreciation				**B17**	**(2,880,985,998)**	**(1,017,251,759)**	**(3,082,463,613)**	**(1,070,959,180)**
Summary of Distribution Plant Depr by Factor								
	S				(2,880,985,998)	(1,017,251,759)	(3,082,463,613)	(1,070,959,180)
Total Distribution Depreciation by Factor					(2,880,985,998)	(1,017,251,759)	(3,082,463,613)	(1,070,959,180)
108GP	General Plant Accumulated Depr							
		G-SITUS	S		(247,578,241)	(84,544,724)	(269,070,144)	(91,832,139)
		G-DGP	SG		(843,233)	(219,431)	(843,233)	(219,431)
		G-DGU	SG		(2,907,693)	(756,658)	(2,907,693)	(756,658)
		G-SG	SG		(113,184,624)	(29,453,619)	(124,641,305)	(32,434,949)
		CUST	CN		(6,314,416)	(1,971,175)	(4,849,240)	(1,513,790)
		PTD	SO		(102,867,839)	(27,995,804)	(106,617,177)	(29,016,198)
		P	SE		(1,583,569)	(397,499)	(1,759,892)	(441,759)
		G-SG	SG		(110,482)	(28,750)	(110,482)	(28,750)
		G-SG	SG		(2,712,809)	(705,944)	(2,712,809)	(705,944)
				B17	(478,102,906)	(146,073,605)	(513,511,975)	(156,949,619)
108MP	Mining Plant Accumulated Depr.							
		P	S		-	-	-	-
		P	SE		-	-	-	-
				B17	-	-	-	-
108MP	Less Centralia Situs Depreciation							
		P	S		-	-	-	-
				B17	-	-	-	-
1081390	Accum Depr - Capital Lease							
		PTD	SO	B17	-	-	-	-
					-	-	-	-
	Remove Capital Leases				-	-	-	-
				B17	-	-	-	-
1081399	Accum Depr - Capital Lease							
		P	S		-	-	-	-
		P	SE	B17	-	-	-	-
					-	-	-	-
	Remove Capital Leases				-	-	-	-
				B17	-	-	-	-
Total General Plant Accum Depreciation				**B17**	**(478,102,906)**	**(146,073,605)**	**(513,511,975)**	**(156,949,619)**
Summary of General Depreciation by Factor								
	S				(247,578,241)	(84,544,724)	(269,070,144)	(91,832,139)
	DGP				-	-	-	-
	DGU				-	-	-	-
	SE				(1,583,569)	(397,499)	(1,759,892)	(441,759)
	SO				(102,867,839)	(27,995,804)	(106,617,177)	(29,016,198)
	CN				(6,314,416)	(1,971,175)	(4,849,240)	(1,513,790)
	SG				(119,758,841)	(31,164,403)	(131,215,522)	(34,145,733)
	DEU				-	-	-	-
	SSGCT				-	-	-	-
	SSGCH				-	-	-	-
	Remove Capital Leases				-	-	-	-
Total General Depreciation by Factor					(478,102,906)	(146,073,605)	(513,511,975)	(156,949,619)
Total Accum Depreciation - Plant In Service				**B17**	**(10,032,916,685)**	**(2,903,746,581)**	**(11,160,312,636)**	**(3,200,067,136)**

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2019 UNADJUSTED RESULTS TOTAL	JUNE 2019 UNADJUSTED RESULTS OREGON	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS OREGON
2481	111SP	Accum Prov for Amort-Steam							
2482			P	SG		-	-	-	-
2483			P	SG		-	-	-	-
2484					B18	-	-	-	-
2485									
2486									
2487	111GP	Accum Prov for Amort-General							
2488			G-SITUS	S		(11,076,917)	(4,176,900)	(11,687,824)	(4,551,753)
2489			CUST	CN		-	-	-	-
2490			I-SG	SG		-	-	-	-
2491			PTD	SO		(3,442,703)	(936,942)	(3,869,233)	(1,053,024)
2492			P	SE		-	-	-	-
2493					B18	(14,519,621)	(5,113,843)	(15,557,057)	(5,604,777)
2494									
2495									
2496	111HP	Accum Prov for Amort-Hydro							
2497			P	SG		-	-	-	-
2498			P	SG		-	-	-	-
2499			P	SG		(2,515,843)	(654,689)	(2,983,387)	(776,356)
2500			P	SG		-	-	-	-
2501					B18	(2,515,843)	(654,689)	(2,983,387)	(776,356)
2502									
2503									
2504	111IP	Accum Prov for Amort-Intangible Plant							
2505			I-SITUS	S		29,199,040	(105,941)	34,376,581	(114,464)
2506			I-DGP	SG		-	-	-	-
2507			I-DGU	SG		(489,827)	(127,466)	(489,827)	(127,466)
2508			P	SE		-	-	1,106,269	277,690
2509			I-SG	SG		(91,016,089)	(23,684,783)	(96,480,725)	(25,106,825)
2510			I-SG	SG		(105,420,483)	(27,433,185)	(112,901,800)	(29,380,021)
2511			I-SG	SG		(6,044,246)	(1,572,872)	(6,516,451)	(1,695,752)
2512			CUST	CN		(137,070,357)	(42,789,334)	(152,460,423)	(47,593,660)
2513			P	SG		-	-	-	-
2514			P	SG		(21,945)	(5,711)	(21,945)	(5,711)
2515			PTD	SO		(290,867,606)	(79,160,528)	(294,501,804)	(80,149,586)
2516					B18	(601,731,514)	(174,879,818)	(627,890,126)	(183,895,794)
2517	111IP	Less Non-Regulated Plant							
2518			NUTIL	OTH		-	-	-	-
2519						(601,731,514)	(174,879,818)	(627,890,126)	(183,895,794)
2520									
2521	111390	Accum Amtr - Capital Lease							
2522			G-SITUS	S		-	-	-	-
2523			P	SG		-	-	-	-
2524			PTD	SO		-	-	-	-
2525					B9	-	-	-	-
2526									
2527		Remove Capital Lease Amtr				-	-	-	-
2528									
2529	**Total Accum Provision for Amortization**				**B18**	**(618,766,978)**	**(180,648,350)**	**(646,430,570)**	**(190,276,927)**
2530									
2531									
2532									
2533									
2534	Summary of Amortization by Factor								
2535		S				18,122,122	(4,282,841)	22,688,757	(4,666,217)
2536		DGP				-	-	-	-
2537		DGU				-	-	-	-
2538		SE				-	-	1,106,269	277,690
2539		SO				(294,310,310)	(80,097,470)	(298,371,037)	(81,202,610)
2540		CN				(137,070,357)	(42,789,334)	(152,460,423)	(47,593,660)
2541		SSGCT				-	-	-	-
2542		SSGCH				-	-	-	-
2543		SG				(205,508,434)	(53,478,705)	(219,394,135)	(57,092,130)
2544		Less Capital Lease				-	-	-	-
2545	Total Provision For Amortization by Factor					(618,766,978)	(180,648,350)	(646,430,570)	(190,276,927)

PacifiCorp
Oregon General Rate Case – December 2021
Revenue Adjustment Index

The Company used actual revenue for the 12 months ended June 30, 2019 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 2021 test period.

Pacificorp
Oregon General Rate Case - December 2021
Tab 3 Adjustment Summary

	Total Adjustments	3.1 Pro Forma Revenue	3.2 Wheeling Revenue	3.3 REC Revenue	3.4 Ancillary Revenue
1 Operating Revenues:					
2 General Business Revenues	44,630,291	44,630,291	-	-	-
3 Interdepartmental	-	-	-	-	-
4 Special Sales	-	-	-	-	-
5 Other Operating Revenues	1,703,647	-	2,320,564	(946,387)	329,471
6 Total Operating Revenues	46,333,938	44,630,291	2,320,564	(946,387)	329,471
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	9,287,901	8,946,395	465,170	(189,709)	66,044
26 Income Taxes - State	2,103,452	2,026,111	105,348	(42,964)	14,957
27 Income Taxes - Def Net	-	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-
30					
31 Total Operating Expenses:	11,391,353	10,972,506	570,518	(232,672)	81,001
32					
33 Operating Rev For Return:	34,942,585	33,657,785	1,750,045	(713,715)	248,469
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	107,671	103,712	5,393	(2,199)	766
45 Weatherization Loans	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-
47					
48 Total Electric Plant:	107,671	103,712	5,393	(2,199)	766
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:	107,671	103,712	5,393	(2,199)	766
62					
63 Return on Rate Base	0.940%	0.905%	0.047%	-0.019%	0.007%
64					
65 Return on Equity	1.756%	1.692%	0.088%	-0.036%	0.012%
66					
67 TAX CALCULATION:					
68 Operating Revenue	46,333,938	44,630,291	2,320,564	(946,387)	329,471
69 Other Deductions		-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-
71 Interest	2,387	2,299	120	(49)	17
72 Schedule "M" Additions	-	-	-	-	-
73 Schedule "M" Deductions	-	-	-	-	-
74 Income Before Tax	46,331,551	44,627,992	2,320,444	(946,339)	329,454
75					
76 State Income Taxes	2,103,452	2,026,111	105,348	(42,964)	14,957
77 Taxable Income	44,228,099	42,601,881	2,215,096	(903,375)	314,496
78					
79 Federal Income Taxes + Other	9,287,901	8,946,395	465,170	(189,709)	66,044
APPROXIMATE PRICE CHANGE	(47,873,811)	(46,113,631)	(2,397,569)	977,792	(340,404)

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Revenues

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Residential	440	3	16,586,832	OR	Situs	16,586,832	3.1.1
Commercial	442	3	19,321,345	OR	Situs	19,321,345	3.1.1
Industrial[1]	442	3	10,626,294	OR	Situs	10,626,294	3.1.1
Public St. & Hwy	444	3	(1,904,180)	OR	Situs	(1,904,180)	3.1.1
Total			44,630,291			44,630,291	3.1.1

[1]Includes Irrigation

Description of Adjustment:

This adjustment normalizes general business revenues by adjusting to the pro forma revenue level for the 12 months ending December 2021 based on forecasted loads. Page 3.1.4 shows a breakout between the TAM and general rate case revenues.

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Revenue Adjustment
Actual 12 Months Ended June 2019
Forecast 12 Months Ending December 2021

	A	B	C	D	E	F	G	H	I	J	K	L	M
	Total Revenue	Normalizing Adjustments[1] (305 Report)	Unadjusted Revenues	Remove Tariff Riders[2]	Base Rate Revenues	Normalizing Adjustments[3]	Temperature Normalization	Total Type 1 Adjusted Revenue	Type 2 Annualized Price Change[4]	Total Type 2 Adjusted Revenue	Type 3 Pro Forma Price Change[5]	Total Oregon Forecast Revenue	**Total Adjustment**
Residential	$607,308,672	$21,963,765	$629,272,437	$18,648,538	$647,920,975	($2,022,919)	$293,477	$646,191,533	($133,079)	$646,058,454	($199,185)	$645,859,269	**$16,586,832**
Commercial	$489,901,122	($14,085,244)	$475,815,879	$12,799,643	$488,615,522	($1,418,698)	($1,519,638)	$485,677,186	$8,509,604	$494,186,790	$950,433	$495,137,223	**$19,321,345**
Industrial	$118,710,891	($2,263,299)	$116,447,592	$4,938,688	$121,386,280	$4,556,799	$0	$125,943,079	$2,219,437	$128,162,516	($492,873)	$127,669,643	**$11,222,051**
Irrigation	$34,845,917	$175,966	$35,021,883	$694,405	$35,716,288	$1,504,063	($661,849)	$36,558,503	$8,007	$36,566,509	($2,140,383)	$34,426,126	**($595,757)**
Public St & Hwy	$6,165,638	($196,331)	$5,969,307	$156,713	$6,126,020	($1,095,473)	$0	$5,030,547	$1,484	$5,032,031	($966,904)	$4,065,127	**($1,904,180)**
Total Oregon	$1,256,932,240	$5,594,858	**$1,262,527,098**	$37,237,987	$1,299,765,084	$1,523,772	($1,888,010)	$1,299,400,847	$10,605,453	$1,310,006,300	($2,848,912)	**$1,307,157,388**	**$44,630,291**
Source / Formula	305 Report		Report Pg. 2, Line 2	Ref. 3.1.8 - B	C + D	Ref. 3.1.9	Ref. 3.1.9	E + F + G	Ref. 3.1.9	H + I	Ref. 3.1.9	J + K	L - C **To. 3.1**

[1,2] Removal of Solar Feed-In Revenue, Gain on Sale of Asset, Revenue Accounting Adjustments, Deferred Net Power Costs, Injuries & Damages Reserve, DSM, Blue Sky, Tax Deferral Adjustments, Pilot Program Cost Adj (Sch 95), Bonneville Power Administration Adj (Sch 98), Federal Tax Act Adj (Sch 195), Deer Creek Mine Undepreciated Investment Adj (Sch 197), Renewable Resource Deferral Adjustment (Sch 203), and Oregon Solar Incentive Program (Sch 204).

[3] Demand Charge Accrual (net zero for calendar year), Rate Mitigation Adj (Sch 299) and Out of Period adjustment.

[4] Transition Adjustment Mechanism (TAM) rate change effective January 1, 2019. Includes adjustment bringing direct access consumers to cost of service.

[5] Renewable Adjustment Clause rate change effective October 1, 2019, December 1, 2019 and January 1, 2020; TAM rate change effective January 1, 2020; adjustment to forecast

PacifiCorp

Oregon General Rate Case - December 2021

Adjustment to MWhs

Historical 12 Months Ended June 2019; Forecast 12 Months Ended December 2021

	A	B	C	D	E	F	G	H
	Total MWhs	Normalizing Adjustments MWhs1	Temperature Adjustments MWhs	Type 1 Adjusted MWhs	Type 2 Adjustments MWhs2	Total Oregon Adjusted Actual MWhs	Type 3 Adjustment MWhs3	Total Oregon Forecast MWhs
Residential	5,615,069	14,590	2,818	5,632,477	(138)	5,632,339	38,795	5,671,134
Commercial	5,373,138	5,784	(22,893)	5,356,030	324,481	5,680,511	36,454	5,716,965
Industrial	1,617,437	2,021	0	1,619,458	68,886	1,688,343	(5,609)	1,682,735
Irrigation	351,867	(398)	(7,635)	343,834	(13)	343,821	(10,440)	333,381
Public St & Hwy	38,375	(322)	0	38,052	(0)	38,052	(5,117)	32,935
Total Oregon	12,995,886	21,675	(27,710)	12,989,850	393,216	13,383,066	54,084	13,437,150
Source / Formula	305 Report	Table 2	Table 2	A + B + C	Table 2	D + E	Table 2	F + G

1 Out of Period adjustment.

2 Adjustment made to reconcile booked MWh with blocking MWh. Includes adjustment to incorporate direct access MWh.

3 Adjustment from actual to forecast.

PacifiCorp PAGE 3.1.3
Oregon General Rate Case - December 2021
Present TAM Revenues In Rates
Forecast 12 Months Ended December 31, 2021

Base Rate Schedule	MWH	TAM Collection (Schedule 201 Revenue)
4	5,521,127	$146,930,537
23	1,130,147	$28,826,759
28	2,038,726	$53,534,641
30	1,361,426	$34,128,818
41	221,554	$5,735,570
47	41,898	$899,034
48	3,079,837	$70,351,368
848	0	$0
15	8,693	$177,106
50	6,032	$101,541
51	13,843	$367,191
52	364	$7,376
53	12,046	$104,076
54	1,457	$21,740
Total	13,437,150	$341,185,758

Comparison to UE 356	MWH	Approved TAM
2020 Test Period	13,579,109	$344,626,127
Difference resulting from change in test period	(141,959)	($3,440,369)
Percentage Change	-1.0%	-1.0%

PacifiCorp PAGE 3.1.4
Oregon General Rate Case - December 2021
Revenue split between TAM and GRC Proforma Revenue

Total Revenue - 2021	TAM/ NPC	NON-TAM / NON NPC
$1,307,157,388	$341,185,758	$965,971,630
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.

	CUSTOMERS			KWH				
					Type 1			
	305 Average Customers	Adjustment Customers	Forecast Customers	305 Booked kWh	Normalizing Adjustment kWh	Temperature Adjustments kWh	Type 1 Adjustments kWh	Total Type 1 Adjusted kWh
Residential								
15	2,402	-142	2,259	2,065,025	13,658		13,658	2,078,683
4	507,299	10,441	517,740	5,467,380,927	12,972,905	2,670,268	15,643,173	5,483,024,100
23	17,084	353	17,437	94,976,447	1,299,939	147,419	1,447,358	96,423,805
28	218	2	220	48,889,076	303,295		303,295	49,192,371
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
Revenue Adjustment - Deferred NPC	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			1,758,000			0	1,758,000
AGA	0			0			0	0
Total Residential	**527,003**	**10,654**	**537,656**	**5,615,069,475**	**14,589,797**	**2,817,687**	**17,407,484**	**5,632,476,959**
Commercial								
15	3,765	-126	3,639	6,645,840	7,681		7,681	6,653,521
23	62,948	1,436	64,384	1,080,889,430	1,087,181	(4,596,909)	(3,509,728)	1,077,379,702
28	9,615	287	9,901	1,946,842,259	3,630,746	(8,347,721)	(4,716,975)	1,942,125,284
30	729	18	747	1,136,505,596	454,549	(4,945,227)	(4,490,678)	1,132,014,918
47	5	0	5	39,357,206	(1,243,000)		(1,243,000)	38,114,206
48	100	1	101	1,163,385,067	1,863,400	(5,002,910)	(3,139,510)	1,160,245,557
54	105	0	105	1,502,587	(16,156)		(16,156)	1,486,431
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
Revenue Adjustment - Deferred NPC	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			(1,990,000)			0	(1,990,000)
AGA	0			0			0	0
Total Commercial	**77,267**	**1,616**	**78,882**	**5,373,137,985**	**5,784,401**	**(22,892,767)**	**(17,108,366)**	**5,356,029,619**
Industrial								
15	124	0	124	272,855	63		63	272,918
23	991	-4	987	18,282,653	58,471	0	58,471	18,341,124
28	438	3	441	91,000,441	(58,450)	0	(58,450)	90,941,991
30	133	0	133	183,726,241	193,660		193,660	183,919,901
47	1	0	1	2,559,837	0		0	2,559,837
48	88	1	89	1,356,117,822	1,827,000		1,827,000	1,357,944,822
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
Revenue Adjustment - Deferred NPC	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			(34,523,000)			0	(34,523,000)
AGA	0			0			0	0
Total Industrial	**1,775**	**(0)**	**1,775**	**1,617,436,849**	**2,020,744**	**0**	**2,020,744**	**1,619,457,593**
Irrigation								
41	7,977	-83	7,894	200,643,482	(408,845)	(5,231,252)	(5,640,097)	195,003,385
23	1	0	1	41,021	10,638		10,638	51,659
48	6	0	6	113,126,400	0	(2,403,858)	(2,403,858)	110,722,542
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
Revenue Adjustment - Deferred NPC	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			38,056,000			0	38,056,000
AGA	0			0			0	0
Total Irrigation	**7,984**	**(83)**	**7,901**	**351,866,903**	**(398,207)**	**(7,635,110)**	**(8,033,317)**	**343,833,586**
Lighting								
15	21	1	22	38,648	0		0	38,648
23	25	-12	13	606,068	(1,775)		(1,775)	604,293
50	231	-2	229	7,339,969	(67,197)		(67,197)	7,272,772
51	832	1	833	19,981,187	(261,301)		(261,301)	19,719,886
52	35	0	35	356,942	8,708		8,708	365,650
53	303	-1	302	11,922,711	(553)		(553)	11,922,158
Solar Feed-In Revenue	0			0			0	0
Gain on Sale of Asset	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Revenue Adjustment - Deferred NPC	0			0			0	0
Revenue Adjustment - I&D Reserve	0			0			0	0
DSM	0			0			0	0
Income Tax Deferral Adjustments	0			0				0
Unbilled	0			(1,871,000)			0	(1,871,000)
AGA	0			0			0	0
Total Lighting	**1,447**	**(13)**	**1,434**	**38,374,525**	**(322,118)**	**0**	**(322,118)**	**38,052,407**
TOTAL COMPANY	**615,477**	**12,172**	**627,649**	**12,995,885,737**	**21,674,617**	**(27,710,190)**	**(6,035,573)**	**12,989,850,164**

	KWH				REVENUES			
	Type 2		Type 3					Type 1
	Blocking Adjustment kWh	Total Type 2 Adjusted kWh	Forecast Adjustment kWh	Total Type 3 Adjusted kWh	305 Booked Revenues	Remove Tariff Riders $	Actual Base Rate Revenues	Normalizing Adjustments $
Residential								
15	11	2,078,694	(124,238)	1,954,456	$319,153	$20,385	$339,538	($46,950)
4	16,603	5,483,040,703	38,085,968	5,521,126,670	$579,880,301	$50,699,889	$630,580,190	($1,672,175)
23	(88,472)	96,335,333	117,755	96,453,088	$12,257,868	$859,618	$13,117,486	($276,631)
28	(65,915)	49,126,456	2,473,352	51,599,808	$4,074,902	$312,828	$4,387,731	($27,162)
BPA Balancing Account		0		0	$1,135,258	($1,135,258)	$0	$0
Solar Feed-In Revenue		0		0	$1,961,096	($1,961,096)	$0	$0
Gain on Sale of Asset		0		0	$11,420	($11,420)	$0	$0
Revenue Accounting Adjustment		0		0	($3,158,308)	$3,158,308	$0	$0
Revenue Adjustment - Deferred NPC		0		0	$0	$0	$0	$0
Revenue Adjustment - I&D Reserve		0		0	$10,478	($10,478)	$0	$0
DSM		0		0	$19,255,296	($19,255,296)	$0	$0
Blue Sky		0		0	$597,344	($597,344)	$0	$0
Income Tax Deferral Adjustments		0		0	($8,532,167)	$8,532,167	$0	$0
Unbilled		1,758,000	(1,758,000)	0	($519,000)	$0	($519,000)	$0
AGA		0		0	$15,031	$0	$15,031	$0
Total Residential	**(137,773)**	**5,632,339,186**	**38,794,836**	**5,671,134,022**	**$607,308,672**	**$40,612,303**	**$647,920,975**	**($2,022,919)**
Commercial								
15	(1)	6,653,520	(227,971)	6,425,549	$995,173	$23,762	$1,018,935	($156,222)
23	456,743	1,077,836,445	(62,534,603)	1,015,301,842	$120,789,365	$1,480,865	$122,270,230	($4,367,233)
28	1,267,502	1,943,392,786	(47,136,141)	1,896,256,645	$178,678,483	$1,886,795	$180,565,279	($1,846,784)
30	42,260,497	1,174,275,415	5,047,558	1,179,322,973	$92,997,500	$900,265	$93,897,764	($415,153)
47	0	38,114,206	1,320,312	39,434,518	$4,004,617	$15,940	$4,020,557	$22,767
48	280,496,401	1,440,741,958	138,024,410	1,578,766,368	$85,238,870	$625,130	$85,864,000	$5,369,235
54	0	1,486,431	(29,304)	1,457,127	$147,132	$1,361	$148,493	($25,308)
BPA Balancing Account		0		0	$26,236	($26,236)	$0	$0
Solar Feed-In Revenue		0		0	$1,735,673	($1,735,673)	$0	$0
Gain on Sale of Asset		0		0	$10,609	($10,609)	$0	$0
Revenue Accounting Adjustment		0		0	($1,022,117)	$1,022,117	$0	$0
Revenue Adjustment - Deferred NPC		0		0	$0	$0	$0	$0
Revenue Adjustment - I&D Reserve		0		0	$7,969	($7,969)	$0	$0
DSM		0		0	$12,581,974	($12,581,974)	$0	$0
Blue Sky		0		0	$739,860	($739,860)	$0	$0
Income Tax Deferral Adjustments		0		0	($7,860,487)	$7,860,487	$0	$0
Unbilled		(1,990,000)	1,990,000	0	($1,789,000)	$0	($1,789,000)	$0
AGA		0		0	$2,619,265	$0	$2,619,265	$0
Total Commercial	**324,481,142**	**5,680,510,761**	**36,454,261**	**5,716,965,022**	**$489,901,122**	**($1,285,600)**	**$488,615,522**	**($1,418,698)**
Industrial								
15	(7)	272,911	1,123	274,034	$38,975	$552	$39,527	($6,459)
23	24	18,341,148	(567,509)	17,773,639	$2,089,637	$22,921	$2,112,559	($70,743)
28	(3)	90,941,988	(72,703)	90,869,285	$8,952,651	$66,448	$9,019,099	($98,780)
30	11	183,919,912	(1,817,212)	182,102,700	$16,681,336	$101,843	$16,783,179	($63,331)
47	0	2,559,837	(96,000)	2,463,837	$1,102,578	$2,661	$1,105,239	$9,058
48	68,885,700	1,426,830,522	(37,579,257)	1,389,251,265	$94,478,721	$575,129	$95,053,850	$4,787,054
BPA Balancing Account		0		0	$66	($66)	$0	$0
Solar Feed-In Revenue		0		0	$850,547	($850,547)	$0	$0
Gain on Sale of Asset		0		0	$3,459	($3,459)	$0	$0
Revenue Accounting Adjustment		0		0	($1,417,514)	$1,417,514	$0	$0
Revenue Adjustment - Deferred NPC		0		0	$0	$0	$0	$0
Revenue Adjustment - I&D Reserve		0		0	$2,606	($2,606)	$0	$0
DSM		0		0	$968,878	($968,878)	$0	$0
Blue Sky		0		0	$443,111	($443,111)	$0	$0
Income Tax Deferral Adjustments		0		0	($2,756,987)	$2,756,987	$0	$0
Unbilled		(34,523,000)	34,523,000	0	($2,873,000)	$0	($2,873,000)	$0
AGA		0		0	$145,827	$0	$145,827	$0
Total Industrial	**68,885,725**	**1,688,343,318**	**(5,608,558)**	**1,682,734,760**	**$118,710,891**	**$2,675,389**	**$121,386,280**	**$4,556,799**
Irrigation								
41	(2,278)	195,001,107	26,553,274	221,554,381	$21,164,985	$1,084,607	$22,249,592	$1,141,784
23	(10,638)	41,021	(34,213)	6,808	$3,940	$150	$4,091	$1,262
48	0	110,722,542	1,097,237	111,819,779	$7,650,761	$345,161	$7,995,923	$353,018
BPA Balancing Account		0		0	$65,344	($65,344)	$0	$0
BPA Adjustment		0		0	$333,861	($333,861)	$0	$0
Demand Charge Accrual		0		0	($8,000)	$0	($8,000)	$8,000
Solar Feed-In Revenue		0		0	$75,995	($75,995)	$0	$0
Gain on Sale of Asset		0		0	$75	($75)	$0	$0
Revenue Accounting Adjustment		0		0	($112,714)	$112,714	$0	$0
Revenue Adjustment - Deferred NPC		0		0	$0	$0	$0	$0
Revenue Adjustment - I&D Reserve		0		0	$449	($449)	$0	$0
DSM		0		0	$652,793	($652,793)	$0	$0
Blue Sky		0		0	$319	($319)	$0	$0
Income Tax Deferral Adjustments		0		0	($456,573)	$456,573	$0	$0
Unbilled		38,056,000	(38,056,000)	0	$5,262,000	$0	$5,262,000	$0
AGA		0		0	$212,682	$0	$212,682	$0
Total Irrigation	**(12,916)**	**343,820,670**	**(10,439,702)**	**333,380,968**	**$34,845,917**	**$870,371**	**$35,716,288**	**$1,504,063**
Lighting								
15	3	38,651	445	39,096	$6,813	$119	$6,932	($914)
23	0	604,293	7,760	612,053	$145,882	$850	$146,732	($2,691)
50	0	7,272,772	(1,241,029)	6,031,743	$967,140	$12,421	$979,561	($167,884)
51	(41)	19,719,845	(5,877,047)	13,842,798	$4,279,700	$56,421	$4,336,121	($770,417)
52	(1)	365,649	(2,121)	363,528	$54,441	$728	$55,169	($6,884)
53	(16)	11,922,142	123,746	12,045,888	$882,049	$10,456	$892,505	($146,684)
Solar Feed-In Revenue		0		0	$10,986	($10,986)	$0	$0
Gain on Sale of Asset		0		0	$662	($662)	$0	$0
Revenue Accounting Adjustment		0		0	($16,594)	$16,594	$0	$0
Revenue Adjustment - Deferred NPC		0		0	$0	$0	$0	$0
Revenue Adjustment - I&D Reserve		0		0	$0	$0	$0	$0
DSM		0		0	$185,384	($185,384)	$0	$0
Income Tax Deferral Adjustments		0		0	($59,824)	$59,824	$0	$0
Unbilled		(1,871,000)	1,871,000	0	($291,000)	$0	($291,000)	$0
AGA		0		0	$0	$0	$0	$0
Total Lighting	**(55)**	**38,052,352**	**(5,117,246)**	**32,935,106**	**$6,165,638**	**($39,618)**	**$6,126,020**	**($1,095,473)**
TOTAL COMPANY	**393,216,123**	**13,383,066,287**	**54,083,591**	**13,437,149,878**	**$1,256,932,240**	**$42,832,844**	**$1,299,765,084**	**$1,523,772**

PacifiCorp
Oregon General Rate Case - December 2021
Historical 12 Months Ended June 2019; Forecast 12 Months Ended December 2021
Revenue, kWH and Customer Adjustments

	REVENUES					
			Type 2		Type 3	
	Temperature Adjustment $	Total Type 1 Adjusted Revenues	Type 2 Adjustments $	Total Type 2 Adjusted Revenues	Type 3 Adjustments $	Total Adjusted Revenues
Residential						
15		$292,588	$521	$293,109	($17,888)	$275,221
4	$279,624	$629,187,639	($117,737)	$629,069,902	($943,802)	$628,126,100
23	$13,853	$12,854,707	($8,937)	$12,845,770	$45,755	$12,891,525
28	$0	$4,360,568	($6,926)	$4,353,642	$197,750	$4,551,392
BPA Balancing Account		$0		$0		$0
Solar Feed-In Revenue		$0		$0		$0
Gain on Sale of Asset		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Revenue Adjustment - Deferred NPC		$0		$0		$0
Revenue Adjustment - I&D Reserve		$0		$0		$0
DSM		$0		$0		$0
Blue Sky		$0		$0		$0
Income Tax Deferral Adjustments		$0		$0		$0
Unbilled		($519,000)		($519,000)	$519,000	$0
AGA		$15,031		$15,031		$15,031
Total Residential	**$293,477**	**$646,191,533**	**($133,079)**	**$646,058,454**	**($199,185)**	**$645,859,269**
Commercial						
15		$862,713	($267)	$862,445	($30,865)	$831,581
23	($422,193)	$117,480,804	($11,974)	$117,468,830	($6,343,947)	$111,124,883
28	($559,089)	$178,159,405	($148,071)	$178,011,334	($4,752,572)	$173,258,762
30	($267,760)	$93,214,852	$966,474	$94,181,326	$128,257	$94,309,583
47		$4,043,324	($426)	$4,042,898	$132,437	$4,175,335
48	($270,596)	$90,962,639	$7,703,890	$98,666,529	$10,030,498	$108,697,027
54		$123,185	($22)	$123,163	($2,375)	$120,788
BPA Balancing Account		$0		$0		$0
Solar Feed-In Revenue		$0		$0		$0
Gain on Sale of Asset		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Revenue Adjustment - Deferred NPC		$0		$0		$0
Revenue Adjustment - I&D Reserve		$0		$0		$0
DSM		$0		$0		$0
Blue Sky		$0		$0		$0
Income Tax Deferral Adjustments		$0		$0		$0
Unbilled		($1,789,000)		($1,789,000)	$1,789,000	$0
AGA		$2,619,265		$2,619,265		$2,619,265
Total Commercial	**($1,519,638)**	**$485,677,186**	**$8,509,604**	**$494,186,790**	**$950,433**	**$495,137,223**
Industrial						
15		$33,068	($18)	$33,050	$66	$33,116
23	$0	$2,041,816	($293)	$2,041,523	($62,183)	$1,979,340
28	$0	$8,920,319	($12,041)	$8,908,278	($36,182)	$8,872,096
30		$16,719,848	($5,996)	$16,713,852	($211,283)	$16,502,569
47		$1,114,297	($64)	$1,114,233	($40,846)	$1,073,387
48		$99,840,904	$2,237,849	$102,078,753	($3,015,445)	$99,063,308
BPA Balancing Account		$0		$0		$0
Solar Feed-In Revenue		$0		$0		$0
Gain on Sale of Asset		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Revenue Adjustment - Deferred NPC		$0		$0		$0
Revenue Adjustment - I&D Reserve		$0		$0		$0
DSM		$0		$0		$0
Blue Sky		$0		$0		$0
Income Tax Deferral Adjustments		$0		$0		$0
Unbilled		($2,873,000)		($2,873,000)	$2,873,000	$0
AGA		$145,827		$145,827		$145,827
Total Industrial	**$0**	**$125,943,079**	**$2,219,437**	**$128,162,516**	**($492,873)**	**$127,669,643**
Irrigation						
41	($531,932)	$22,859,444	$13,794	$22,873,238	$3,073,873	$25,947,111
23	$0	$5,353	($1,672)	$3,681	($2,897)	$784
48	($129,917)	$8,219,024	($4,116)	$8,214,908	$50,641	$8,265,549
BPA Balancing Account		$0		$0		$0
BPA Adjustment		$0		$0		$0
Demand Charge Accrual		$0		$0		$0
Solar Feed-In Revenue		$0		$0		$0
Gain on Sale of Asset		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Revenue Adjustment - Deferred NPC		$0		$0		$0
Revenue Adjustment - I&D Reserve		$0		$0		$0
DSM		$0		$0		$0
Blue Sky		$0		$0		$0
Income Tax Deferral Adjustments		$0		$0		$0
Unbilled		$5,262,000		$5,262,000	($5,262,000)	$0
AGA		$212,682		$212,682		$212,682
Total Irrigation	**($661,849)**	**$36,558,503**	**$8,007**	**$36,566,509**	**($2,140,383)**	**$34,426,126**
Lighting						
15		$6,018	$192	$6,210	$58	$6,268
23		$144,041	($23)	$144,018	($59,722)	$84,296
50		$811,678	$238	$811,916	($139,134)	$672,781
51		$3,565,704	$1,179	$3,566,883	($1,067,509)	$2,499,374
52		$48,285	($58)	$48,227	($299)	$47,929
53		$745,821	($44)	$745,777	$8,702	$754,478
Solar Feed-In Revenue		$0		$0		$0
Gain on Sale of Asset		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Revenue Adjustment - Deferred NPC		$0		$0		$0
Revenue Adjustment - I&D Reserve		$0		$0		$0
DSM		$0		$0		$0
Income Tax Deferral Adjustments		$0		$0		$0
Unbilled		($291,000)		($291,000)	$291,000	$0
AGA		$0		$0		$0
Total Lighting	**$0**	**$5,030,547**	**$1,484**	**$5,032,031**	**($966,904)**	**$4,065,127**
TOTAL COMPANY	**($1,888,010)**	**$1,299,400,847**	**$10,605,453**	**$1,310,006,300**	**($2,848,912)**	**$1,307,157,388**

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Revenue
Historical 12 Months Ended June 2019; Forecast 12 Months Ended December 2021
Revenue Adjustments

									Remove Tariff Riders							
	305 Booked Revenues	Solar Feed-In Revenue	Gain on Sale of Asset	Revenue Accounting Adjustments	Revenue Adjustment Deferred NPC	Revenue Adjustment I&D Reserve	DSM Revenue	Blue Sky Revenue	Income Tax Deferral Adjustments	Sch 98 BPA Adjust	Sch 95 Pilot Cost Adj. Adjust	Sch 192 Def. Acctng. Adjust	Sch 195 Fed. Tax Act Adjust	Sch 197 Deer Crk Adjust	Sch 203 Renw Rsrc Def Adjust	Sch 204 OSIP Adjust
Residential																
15	$319,153									$16,293	($21)	$888	$4,338	($454)	($83)	($576)
4	$579,880,301									$43,887,953	($54,674)	$2,077,605	$8,949,676	($1,911,385)	($273,369)	($1,975,917)
23	$12,257,868									$741,185	($950)	$35,141	$152,576	($31,180)	($4,749)	($32,407)
28	$4,074,902									$277,167	($489)	$14,667	$57,628	($16,693)	($2,444)	($17,007)
BPA Balancing Account	$1,135,258									($1,135,258)						
Solar Feed-In Revenue	$1,961,096	($1,961,096)														
Gain on Sale of Asse	$11,420		($11,420)													
Revenue Accounting Adjustmen	($3,158,308)			$3,158,308												
Revenue Adjustment - Deferred NPC	$0				$0											
Revenue Adjustment - I&D Reserve	$10,478					($10,478)										
DSM	$19,255,296						($19,255,296)									
Blue Sky	$597,344							($597,344)								
Income Tax Deferral Adjustments	($8,532,167)								$8,532,167							
Unbilled	($519,000)															
AGA	$15,031															
Total Residential	**$607,308,672**	**($1,961,096)**	**($11,420)**	**$3,158,308**	**$0**	**($10,478)**	**($19,255,296)**	**($597,344)**	**$8,532,167**	**$43,787,340**	**($56,133)**	**$2,128,301**	**$9,164,218**	**($1,959,712)**	**($280,645)**	**($2,025,906)**
Commercial																
15	$995,173									$10,951	($66)	$2,858	$13,591	($1,476)	($266)	($1,829)
23	$120,789,365									$197,990	($10,810)	$399,964	$1,672,671	($354,318)	($54,049)	($370,583)
28	$178,678,483									$500,675	($19,481)	$584,443	$2,253,933	($655,281)	($97,407)	($680,086)
30	$92,997,500									$272,725	($11,787)	$318,261	$1,150,716	($376,755)	($58,937)	($393,957)
47	$4,004,617									$0	($394)	$9,446	$32,667	($11,647)	($1,968)	($12,164)
48	$85,238,870									$24,012	($14,439)	$346,532	$1,193,833	($419,724)	($59,589)	($445,494)
54	$147,132									$0	($15)	$421	$1,667	($360)	($45)	($307)
BPA Balancing Account	$26,236									($26,236)						
Solar Feed-In Revenue	$1,735,673	($1,735,673)														
Gain on Sale of Asse	$10,609		($10,609)													
Revenue Accounting Adjustmen	($1,022,117)			$1,022,117												
Revenue Adjustment - Deferred NPC	$0				$0											
Revenue Adjustment - I&D Reserve	$7,969					($7,969)										
DSM	$12,581,974						($12,581,974)									
Blue Sky	$739,860							($739,860)								
Income Tax Deferral Adjustments	($7,860,487)								$7,860,487							
Unbilled	($1,789,000)															
AGA	$2,619,265															
Total Commercial	**$489,901,122**	**($1,735,673)**	**($10,609)**	**$1,022,117**	**$0**	**($7,969)**	**($12,581,974)**	**($739,860)**	**$7,860,487**	**$980,116**	**($56,993)**	**$1,661,924**	**$6,319,077**	**($1,819,561)**	**($272,261)**	**($1,904,421)**
Industrial																
15	$38,975									$23	($3)	$117	$561	($60)	($11)	($75)
23	$2,089,637									$732	($183)	$6,765	$28,780	($6,005)	($914)	($6,254)
28	$8,952,651									$1,153	($910)	$27,300	$105,717	($30,487)	($4,550)	($31,775)
30	$16,681,336									$0	($1,837)	$49,606	$182,993	($58,429)	($9,186)	($61,304)
47	$1,102,578									$0	($26)	$614	$3,556	($593)	($128)	($764)
48	$94,478,721									$0	($14,250)	$342,001	$1,173,555	($415,220)	($71,250)	($439,706)
BPA Balancing Account	$66									($66)						
Solar Feed-In Revenue	$850,547	($850,547)														
Gain on Sale of Asse	$3,459		($3,459)													
Revenue Accounting Adjustmen	($1,417,514)			$1,417,514												
Revenue Adjustment - Deferred NPC	$0				$0											
Revenue Adjustment - I&D Reserve	$2,606					($2,606)										
DSM	$968,878						($968,878)									
Blue Sky	$443,111							($443,111)								
Income Tax Deferral Adjustments	($2,756,987)								$2,756,987							
Unbilled	($2,873,000)															
AGA	$145,827															
Total Industrial	**$118,710,891**	**($850,547)**	**($3,459)**	**$1,417,514**	**$0**	**($2,606)**	**($968,878)**	**($443,111)**	**$2,756,987**	**$1,843**	**($17,208)**	**$426,403**	**$1,495,162**	**($510,794)**	**($86,040)**	**($539,877)**
Irrigation																
41	$21,164,985									$963,980	($2,006)	$76,245	$196,793	($68,324)	($10,032)	($72,048)
23	$3,940									$0	($0)	$15	$149	$2	($2)	($13)
48	$7,650,761									$340,747	($1,131)	$27,150	$54,609	($34,367)	($5,656)	($36,189)
BPA Balancing Account	$65,344									($65,344)						
BPA Adjustment	$333,861									($333,861)						
Demand Charge Accrua	($8,000)															
Solar Feed-In Revenue	$75,995	($75,995)														
Gain on Sale of Asse	$75		($75)													
Revenue Accounting Adjustmen	($112,714)			$112,714												
Revenue Adjustment - Deferred NPC	$0				$0											
Revenue Adjustment - I&D Reserve	$449					($449)										
DSM	$652,793						($652,793)									
Blue Sky	$319							($319)								
Income Tax Deferral Adjustments	($456,573)								$456,573							
Unbilled	$5,262,000															
AGA	$212,682															
Total Irrigation	**$34,845,917**	**($75,995)**	**($75)**	**$112,714**	**$0**	**($449)**	**($652,793)**	**($319)**	**$456,573**	**$905,522**	**($3,138)**	**$103,410**	**$251,551**	**($102,690)**	**($15,691)**	**($108,250)**
Lighting																
15	$6,813									$39	($0)	$17	$84	($8)	($2)	($11)
23	$145,882									$0	($6)	$224	$1,050	($182)	($30)	($206)
50	$967,140									$0	($73)	$2,716	$13,290	($1,621)	($220)	($1,671)
51	$4,279,700									$0	($200)	$11,589	$57,384	($4,375)	($999)	($6,977)
52	$54,441									$0	($4)	$153	$768	($78)	($14)	($97)
53	$882,049									$0	($119)	$2,504	$12,332	($2,649)	($238)	($1,374)
Solar Feed-In Revenue	$10,986	($10,986)														
Gain on Sale of Asse	$662		($662)													
Revenue Accounting Adjustmen	($16,594)			$16,594												
Revenue Adjustment - Deferred NPC	$0				$0											
Revenue Adjustment - I&D Reserve	$0					$0										
DSM	$185,384						($185,384)									
Income Tax Deferral Adjustments	($59,824)								$59,824							
Unbilled	($291,000)															
AGA	$0															
Total Lighting	**$6,165,638**	**($10,986)**	**($662)**	**$16,594**	**$0**	**$0**	**($185,384)**	**$0**	**$59,824**	**$39**	**($402)**	**$17,203**	**$84,909**	**($8,914)**	**($1,504)**	**($10,336)**
TOTAL COMPANY	**$1,256,932,240**	**($4,634,297)**	**($26,223)**	**$5,727,247**	**$0**	**($21,503)**	**($33,644,324)**	**($1,780,634)**	**$19,666,038**	**$45,674,859**	**($133,875)**	**$4,337,241**	**$17,314,916**	**($4,401,671)**	**($656,140)**	**($4,588,791)**

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Revenue
Historical 12 Months Ended June 2019; Forecast 12 Months Ended December 2021
Revenue Adjustments

	Total Remove Tariff Riders	Actual Base Rate Revenues	Demand Charge Accrual	Sch 299 RMA Adjust	Out of Period Adjust	Subtotal Normalization Adjustments	Temperature Adjustment	Total Type 1 Adjusted Revenues	Type 2 Price Changes	Total Type 2 Adj.	Total Type 2 Adjusted Revenues	Type 3 Price Changes	Adjustment to Forecast	Total Type 3 Adj.	Total Type 3 Adjusted Revenues
Residential															
15	$20,385	$339,538		($48,838)	$1,888	($46,950)		$292,588	$521	$521	$293,109	($395)	($17,493)	($17,888)	$275,221
4	$50,699,889	$630,580,190		($3,174,552)	$1,502,377	($1,672,175)	$279,624	$629,187,639	($117,737)	($117,737)	$629,069,902	($6,323,050)	$5,379,248	($943,802)	$628,126,100
23	$859,618	$13,117,486		($394,734)	$118,103	($276,631)	$13,853	$12,854,707	($8,937)	($8,937)	$12,845,770	($44,143)	$89,898	$45,755	$12,891,525
28	$312,828	$4,387,731		($55,228)	$28,066	($27,162)		$4,360,568	($6,926)	($6,926)	$4,353,642	($16,812)	$214,562	$197,750	$4,551,392
BPA Balancing Accoun	($1,135,258)	$0				$0		$0			$0			$0	$0
Solar Feed-In Revenu	($1,961,096)	$0				$0		$0			$0			$0	$0
Gain on Sale of Asse	($11,420)	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustmen	$3,158,308	$0				$0		$0			$0			$0	$0
Revenue Adjustment - Deferred NP(	$0	$0				$0		$0			$0			$0	$0
Revenue Adjustment - I&D Reserv	($10,478)	$0				$0		$0			$0			$0	$0
DSM	($19,255,296)	$0				$0		$0			$0			$0	$0
Blue Sky	($597,344)	$0				$0		$0			$0			$0	$0
Income Tax Deferral Adjustment	$8,532,167	$0				$0		$0			$0			$0	$0
Unbilled	$0	($519,000)				$0		($519,000)			($519,000)		$519,000	$519,000	$0
AGA	$0	$15,031				$0		$15,031			$15,031			$0	$15,031
Total Residential	**$40,612,303**	**$647,920,975**	**$0**	**($3,673,353)**	**$1,650,434**	**($2,022,919)**	**$293,477**	**$646,191,533**	**($133,079)**	**($133,079)**	**$646,058,454**	**($6,384,400)**	**$6,185,215**	**($199,185)**	**$645,859,269**
Commercial															
15	$23,762	$1,018,935		($157,174)	$952	($156,222)		$862,713	($267)	($267)	$862,445	($1,347)	($29,518)	($30,865)	$831,581
23	$1,480,865	$122,270,230		($4,498,400)	$131,167	($4,367,233)	($422,193)	$117,480,804	($11,974)	($11,974)	$117,468,830	($422,514)	($5,921,433)	($6,343,947)	$111,124,883
28	$1,886,795	$180,565,279		($2,201,403)	$354,618	($1,846,784)	($559,089)	$178,159,405	($148,071)	($148,071)	$178,011,334	($670,059)	($4,082,513)	($4,752,572)	$173,258,762
30	$900,265	$93,897,764		($459,728)	$44,575	($415,153)	($267,760)	$93,214,852	$966,474	$966,474	$94,181,326	($337,340)	$465,597	$128,257	$94,309,583
47	$15,940	$4,020,557		$136,964	($114,198)	$22,767		$4,043,324	($426)	($426)	$4,042,898	($5,104)	$137,541	$132,437	$4,175,335
48	$625,130	$85,864,000		$5,234,042	$135,193	$5,369,235	($270,596)	$90,962,639	$7,703,890	$7,703,890	$98,666,529	($292,448)	$10,322,946	$10,030,498	$108,697,027
54	$1,361	$148,493		($23,891)	($1,417)	($25,308)		$123,185	($22)	($22)	$123,163	($118)	($2,257)	($2,375)	$120,788
BPA Balancing Accoun	($26,236)	$0				$0		$0			$0			$0	$0
Solar Feed-In Revenu	($1,735,673)	$0				$0		$0			$0			$0	$0
Gain on Sale of Asse	($10,609)	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustmen	$1,022,117	$0				$0		$0			$0			$0	$0
Revenue Adjustment - Deferred NP(	$0	$0				$0		$0			$0			$0	$0
Revenue Adjustment - I&D Reserv	($7,969)	$0				$0		$0			$0			$0	$0
DSM	($12,581,974)	$0				$0		$0			$0			$0	$0
Blue Sky	($739,860)	$0				$0		$0			$0			$0	$0
Income Tax Deferral Adjustment	$7,860,487	$0				$0		$0			$0			$0	$0
Unbilled	$0	($1,789,000)				$0		($1,789,000)			($1,789,000)		$1,789,000	$1,789,000	$0
AGA	$0	$2,619,265				$0		$2,619,265			$2,619,265			$0	$2,619,265
Total Commercial	**($1,285,600)**	**$488,615,522**	**$0**	**($1,969,589)**	**$550,891**	**($1,418,698)**	**($1,519,638)**	**$485,677,186**	**$8,509,604**	**$8,509,604**	**$494,186,790**	**($1,728,930)**	**$2,679,363**	**$950,433**	**$495,137,223**
Industrial															
15	$552	$39,527		($6,453)	($6)	($6,459)		$33,068	($18)	($18)	$33,050	($68)	$133	$66	$33,116
23	$22,921	$2,112,559		($76,056)	$5,313	($70,743)	$0	$2,041,816	($293)	($293)	$2,041,523	($7,281)	($54,902)	($62,183)	$1,979,340
28	$66,448	$9,019,099		($102,830)	$4,050	($98,780)	$0	$8,920,319	($12,041)	($12,041)	$8,908,278	($30,930)	($5,252)	($36,182)	$8,872,096
30	$101,843	$16,783,179		($71,653)	$8,322	($63,331)		$16,719,848	($5,996)	($5,996)	$16,713,852	($54,023)	($157,260)	($211,283)	$16,502,569
47	$2,661	$1,105,239		$9,058	$0	$9,058		$1,114,297	($64)	($64)	$1,114,233	$228	($41,074)	($40,846)	$1,073,387
48	$575,129	$95,053,850		$4,638,325	$148,729	$4,787,054		$99,840,904	$2,237,849	$2,237,849	$102,078,753	($353,817)	($2,661,628)	($3,015,445)	$99,063,308
BPA Balancing Accoun	($66)	$0				$0		$0			$0			$0	$0
Solar Feed-In Revenu	($850,547)	$0				$0		$0			$0			$0	$0
Gain on Sale of Asse	($3,459)	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustmen	$1,417,514	$0				$0		$0			$0			$0	$0
Revenue Adjustment - Deferred NP(	$0	$0				$0		$0			$0			$0	$0
Revenue Adjustment - I&D Reserv	($2,606)	$0				$0		$0			$0			$0	$0
DSM	($968,878)	$0				$0		$0			$0			$0	$0
Blue Sky	($443,111)	$0				$0		$0			$0			$0	$0
Income Tax Deferral Adjustment	$2,756,987	$0				$0		$0			$0			$0	$0
Unbilled	$0	($2,873,000)				$0		($2,873,000)			($2,873,000)		$2,873,000	$2,873,000	$0
AGA	$0	$145,827				$0		$145,827			$145,827			$0	$145,827
Total Industrial	**$2,675,389**	**$121,386,280**	**$0**	**$4,390,391**	**$166,408**	**$4,556,799**	**$0**	**$125,943,079**	**$2,219,437**	**$2,219,437**	**$128,162,516**	**($445,891)**	**($46,983)**	**($492,873)**	**$127,669,643**
Irrigation															
41	$1,084,607	$22,249,592		$1,193,770	($51,986)	$1,141,784	($531,932)	$22,859,444	$13,794	$13,794	$22,873,238	($58,469)	$3,132,342	$3,073,873	$25,947,111
23	$150	$4,091		($126)	$1,388	$1,262		$5,353	($1,672)	($1,672)	$3,681	($4)	($2,893)	($2,897)	$784
48	$345,161	$7,995,923		$353,018	$0	$353,018	($129,917)	$8,219,024	($4,116)	($4,116)	$8,214,908	($29,972)	$80,613	$50,641	$8,265,549
BPA Balancing Accoun	($65,344)	$0				$0		$0			$0			$0	$0
BPA Adjustment	($333,861)	$0				$0		$0			$0			$0	$0
Demand Charge Accrua	$0	($8,000)	$8,000			$8,000		$0			$0			$0	$0
Solar Feed-In Revenu	($75,995)	$0				$0		$0			$0			$0	$0
Gain on Sale of Asse	($75)	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustmen	$112,714	$0				$0		$0			$0			$0	$0
Revenue Adjustment - Deferred NP(	$0	$0				$0		$0			$0			$0	$0
Revenue Adjustment - I&D Reserv	($449)	$0				$0		$0			$0			$0	$0
DSM	($652,793)	$0				$0		$0			$0			$0	$0
Blue Sky	($319)	$0				$0		$0			$0			$0	$0
Income Tax Deferral Adjustment	$456,573	$0				$0		$0			$0			$0	$0
Unbilled	$0	$5,262,000				$0		$5,262,000			$5,262,000		($5,262,000)	($5,262,000)	$0
AGA	$0	$212,682				$0		$212,682			$212,682			$0	$212,682
Total Irrigation	**$870,371**	**$35,716,288**	**$8,000**	**$1,546,661**	**($50,598)**	**$1,504,063**	**($661,849)**	**$36,558,503**	**$8,007**	**$8,007**	**$36,566,509**	**($88,445)**	**($2,051,938)**	**($2,140,383)**	**$34,426,126**
Lighting															
15	$119	$6,932		($914)	$0	($914)		$6,018	$192	$192	$6,210	($7)	$65	$58	$6,268
23	$850	$146,732		($2,521)	($170)	($2,691)		$144,041	($23)	($23)	$144,018	($309)	($59,413)	($59,722)	$84,296
50	$12,421	$979,561		($160,232)	($7,652)	($167,884)		$811,678	$238	$238	$811,916	($727)	($138,407)	($139,134)	$672,781
51	$56,421	$4,336,121		($721,120)	($49,297)	($770,417)		$3,565,704	$1,179	$1,179	$3,566,883	($6,366)	($1,061,142)	($1,067,509)	$2,499,374
52	$728	$55,169		($7,995)	$1,112	($6,884)		$48,285	($58)	($58)	$48,227	($25)	($274)	($299)	$47,929
53	$10,456	$892,505		($146,649)	($35)	($146,684)		$745,821	($44)	($44)	$745,777	$954	$7,747	$8,702	$754,478
Solar Feed-In Revenu	($10,986)	$0				$0		$0			$0			$0	$0
Gain on Sale of Asse	($662)	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustmen	$16,594	$0				$0		$0			$0			$0	$0
Revenue Adjustment - Deferred NP(	$0	$0				$0		$0			$0			$0	$0
Revenue Adjustment - I&D Reserv	$0	$0				$0		$0			$0			$0	$0
DSM	($185,384)	$0				$0		$0			$0			$0	$0
Income Tax Deferral Adjustment	$59,824	$0				$0		$0			$0			$0	$0
Unbilled	$0	($291,000)				$0		($291,000)			($291,000)		$291,000	$291,000	$0
AGA	$0	$0				$0		$0			$0			$0	$0
Total Lighting	**($39,618)**	**$6,126,020**	**$0**	**($1,039,431)**	**($56,042)**	**($1,095,473)**	**$0**	**$5,030,547**	**$1,484**	**$1,484**	**$5,032,031**	**($6,479)**	**($960,425)**	**($966,904)**	**$4,065,127**
TOTAL COMPANY	**$42,832,844**	**$1,299,765,084**	**$8,000**	**($745,321)**	**$2,261,093**	**$1,523,772**	**($1,888,010)**	**$1,299,400,847**	**$10,605,453**	**$10,605,453**	**$1,310,006,300**	**($8,654,144)**	**$5,805,233**	**($2,848,912)**	**$1,307,157,388**

PacifiCorp
Oregon General Rate Case - December 2021
Wheeling Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenues:							
Other Electric Revenues	456	1	(322,560)	SG	26.023%	(83,939)	3.2.1
Other Electric Revenues	456	2	237,261	SG	26.023%	61,742	3.2.1
Other Electric Revenues	456	3	9,002,780	SG	26.023%	2,342,760	3.2.1
			8,917,482			2,320,564	
Adjustment Detail:							
Actual Wheeling Revenues 12 ME June 2019			115,311,933				3.2.1
Total Adjustments			8,917,482				Above
Adjusted Wheeling Revenues 12 ME December 2021			124,229,415				3.2.1

Description of Adjustment:

This adjustment removes out-of-period and one-time adjustments from the 12 months ended June 2019 and adds in pro forma changes through December 2021.

PacifiCorp
Oregon General Rate Case - December 2021
Wheeling Revenue

Customer	Total
3 Phases Renewables, Inc.	(1,368)
Avangrid Renewables, LLC	(6,077,922)
Avista Corporation	(20,985)
BASIN ELECTRIC POWER COOPERATIVE	(1,873,667)
BLACK HILLS POWER & LIGHT COMPANY	(3,860,257)
BONNEVILLE POWER ADMINISTRATION	(16,667,343)
BONNEVILLE POWER ADMINISTRATION	(4,472,439)
Brookfield Energy Marketing L.P.	(89,212)
Calpine Energy Solutions, LLC	(1,222,740)
City of Anaheim	(1,205)
City of Roseville	(1,629,586)
Clatskanie PUD	(1,040,170)
Colorado Electric Utility Co.	(5,322)
Constellation NewEnergy, Inc.	(37,423)
CONSTELLATION POWER SOURCE, INC.	(1,526,735)
DESERET GENERATION & TRANS. CO-OP.	(4,584,913)
Eagle Energy Partners I LP	(5,897)
Eugene Water & Electric Board	(571,516)
Evergreen BioPower	(379,381)
FALL RIVER RURAL ELECTRIC COOPERATI	(151,308)
Idaho Power Co. Balancing Ops	(1,108,637)
Intermountain Renewable(Cyrq Enrgy)	(411,124)
Los Angeles Dept. of Water & Power	(1,238,409)
Macquarie Energy LLC	(390,017)
MAG Energy Solutions Inc.	(105,986)
Moon Lake Electric Association	(19,262)
MORGAN STANLEY CAPITAL	(5,425,643)
Municipal Energy Agency of Nebraska	(7,211)
Navajo Tribal Utility Authority	(68,814)
NextEra Energy Resources, LLC	(3,276,886)
NV Energy	(402,587)
PACIFIC GAS & ELECTRIC COMPANY	(154,526)
PORTLAND GENERAL ELECTRIC COMPANY	(301,115)
POWEREX	(20,409,950)
PUBLIC SERVICE COMPANY OF COLORADO	(25)
RAINBOW ENERGY MARKETING CORPORATIO	(180,670)
Sacramento Municipal Utility Dist	(654,849)
Salt River Project	(866,003)
SeaWest Windpower, Inc.	(67,585)
Shell Energy NA (Coral Power)	(2,770,900)
SIERRA PACIFIC POWER COMPANY	(36,159)
Simplot Phosphates, LLC	(3,887)
So. Cal Public Power Authority	(24,972)
Southern California Edison Company	(3,708,795)
State of South Dakota	(137,863)
Tenaska Power Services Company	(360,788)
The Energy Authority	(54,939)
TRANSALTA ENERGY MARKETING CORP.	(339,277)
TRI-STATE GEN. & TRANS. ASSOCIATION	(582,649)
U.S. Bureau of Reclamation	(59,859)
UTAH ASSOCIATED MUNICIPAL POWER SYS	(18,724,538)
UTAH MUNICIPAL POWER AGENCY	(3,287,302)
Warm Springs Power Enterprises	(119,700)
Westar Energy, Inc.	(24,497)
WESTERN AREA POWER ADMIN. - UT	(3,234,598)
WESTERN AREA POWER ADMINISTRATION	(112,915)
Enel Cove Fort LLC	(119,620)
Cowlitz Revenue	(181,067)
Accruals and Adjustments	(2,118,921)
Total	**(115,311,933)**
	Ref 3.2

Type		
1	Remove refunds and other out of period adjustments	322,560
2	Annualize EWEB 25MW PTP	(652,832)
2	Annualize Navajo Tribal Utility Authority	(13,854)
2	Clatskanie Reduction of Reservation	429,424
2	BPA Idaho Falls	-
3	Obsidian Renewables 50MW PTP	(2,070,535)
3	Obsidian Renewables 10MW PTP	(414,107)
3	BPA Lost Creek to Network	2,226,121
3	BPA Green Springs to Network	715,539
3	Forecasted Price/Volume Increase	(9,459,798)
	Incremental Adjustments	**(8,917,482)**
		Ref 3.2
	Accum Totals	**(124,229,415)**
		Ref 3.2

PacifiCorp
Oregon General Rate Case - December 2021
REC Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Remove:							
June 2019 Booked Revenues (Including Accruals)	456	1	(3,760,979)	SG	26.023%	(978,706)	3.3.1
June 2019 REC Deferrals	456	1	130,053	SG	26.023%	33,843	3.3.1
June 2019 Leaning Juniper Indemnity	456	1	(5,859)	SG	26.023%	(1,525)	3.3.1

Description of Adjustment:

This adjustment removes all REC revenues as booked during the 12 months ended June 2019. Most of Oregon's share of the renewable energy certificates (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 2019.

PacifiCorp
Oregon General Rate Case - December 2021
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-18	(593)	632	(171,000)	(170,961)
August-18	(625)	593	-	(32)
September-18	(415)	625	-	210
October-18	(681,860)	415	-	(681,445)
November-18	(462,882)	681,860	(693,122)	(474,144)
December-18	(32,948)	462,882	(466,703)	(36,770)
January-19	(109)	32,948	(192,815)	(159,976)
February-19	(919,873)	109	-	(919,764)
March-19	(278,133)	919,873	(1,078,766)	(437,026)
April-19	(296,559)	278,133	(277,994)	(296,419)
May-19	(262,337)	296,559	(296,200)	(261,978)
June-19	(323,878)	262,337	(261,134)	(322,675)
12 ME June 2019	(3,260,211)	2,936,965	(3,437,734)	**(3,760,979)**
				Ref. 3.3

REC Deferrals Included in Unadjusted Results:

FERC Account	4562700	
Amount 12 ME June 2019	**130,053**	**Ref. 3.3**

Leaning Juniper indemnity revenue included in unadjusted results:

FERC Account	4562700	
Amount 12 ME June 2019	**5,859**	**Ref. 3.3.2**

PacifiCorp Page 3.3.2
Oregon General Rate Case - December 2021
REC Revenue
Actuals as Booked - Leaning Juniper Indemnity

Posting Date	Amount	
FERC Account	4562700	
SAP Account	352950	
July-18	($819)	
August-18	($768)	
September-18	($810)	
October-18	($538)	
November-18	($297)	
December-18	($338)	
January-19	($174)	
February-19	($154)	
March-19	($175)	
April-19	($883)	
May-19	($495)	
June-19	($409)	
Total	**($5,859)**	**Ref 3.3**

PacifiCorp
Oregon General Rate Case - December 2021
Ancillary Revenues

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Ancillary Contract Renewal	456	3	1,266,093	SG	26.023%	329,471	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 2021
Ancillary Revenues

Description	12 ME June 2019	12 ME December 2021	Incremental Change	FERC Acct	Alloc. Factor
SCL Stateline Demand & Energy	9,234,829	11,351,003	2,116,174	456	SG
BPA Foote Creek 4 Ancillary Service	742,694	-	(742,694)	456	SG
BPA Foote Creek 1 Ancillary Service	63,322	-	(63,322)	456	SG
EWEB Foote Creek 1 O&M	203,552	-	(203,552)	456	SG
EWEB Facilities Credit	(202,709)	-	202,709	456	SG
EWEB Facilities Charge	43,223	-	(43,223)	456	SG
	10,084,911	**11,351,003**	**1,266,093**		
			Ref. 3.4		

PacifiCorp
Oregon General Rate Case – December 2021
Operation & Maintenance Expense Adjustment Index

The Company's June 2019 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 2021 test period. The following adjustments are included:

4.1 Miscellaneous General Expense and Revenues
4.2 Wage & Employee Benefits Adjustment
4.3 Revenue Sensitive Items & Uncollectible Expense
4.4 Insurance Expense
4.5 Generation Overhaul Expense
4.6 Memberships and Subscriptions
4.7 Incremental O&M Expense
4.8 Paperless Bill Credits Adjustment
4.9 Credit Facility Fees Adjustment
4.10 Remove Non-Recurring Entries
4.11 O&M Expense Escalation

Pacificorp
Oregon General Rate Case - December 2021
Tab 4 Adjustment Summary

	Total Adjustments	4.1 Miscellaneous General Expenses & Revenues	4.2 Wage & Employee Benefits Adjustment	4.3 Revenue Sensitive Items & Uncollectible Expense	4.4 Insurance Expense	4.5 Generation Overhaul Expense	4.6 Memberships and Subscriptions
1 Operating Revenues:							
2 General Business Revenues	1,727,327	1,727,327	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-
5 Other Operating Revenues	(1,373,862)	-	-	-	-	-	-
6 Total Operating Revenues	353,465	1,727,327	-	-	-	-	-
7							
8 Operating Expenses:							
9 Steam Production	4,699,824	-	3,133,684	-	-	(400,846)	-
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	732,670	-	611,972	-	-	-	-
12 Other Power Supply	3,155,329	(1,344)	1,184,868	-	-	273,811	-
13 Transmission	1,215,813	-	940,733	-	-	-	-
14 Distribution	9,470,192	(161,609)	4,304,827	-	-	-	-
15 Customer Accounting	2,406,815	(23,549)	1,655,379	163,705	-	-	-
16 Customer Service & Info	450,160	25,444	321,126	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	2,337,441	(30,938)	1,432,911	178,521	(650,646)	-	(182,052)
19							
20 Total O&M Expenses	24,468,244	(191,996)	13,585,501	342,226	(650,646)	(127,035)	(182,052)
21		-	-	-	-	-	-
22 Depreciation	-	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-	-
24 Taxes Other Than Income	1,106,296	-	-	1,106,296	-	-	-
25 Income Taxes - Federal	(5,241,091)	200,438	(2,723,861)	(290,425)	130,453	25,470	36,501
26 Income Taxes - State	(1,186,962)	45,394	(616,879)	(65,773)	29,544	5,768	8,266
27 Income Taxes - Def Net	-	-	-	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	919,453	919,453	-	-	-	-	-
30							
31 Total Operating Expenses:	20,065,939	973,289	10,244,761	1,092,323	(490,649)	(95,796)	(137,285)
32							
33 Operating Rev For Return:	(19,712,474)	754,038	(10,244,761)	(1,092,323)	490,649	95,796	137,285
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	180,973	509	96,834	10,325	(4,638)	(905)	(1,298)
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	180,973	509	96,834	10,325	(4,638)	(905)	(1,298)
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:	180,973	509	96,834	10,325	(4,638)	(905)	(1,298)
62							
63 Return on Rate Base	-0.531%	0.020%	-0.276%	-0.029%	0.013%	0.003%	0.004%
64							
65 Return on Equity	-0.992%	0.038%	-0.515%	-0.055%	0.025%	0.005%	0.007%
66							
67 TAX CALCULATION:							
68 Operating Revenue	(26,140,528)	999,869	(13,585,501)	(1,448,521)	650,646	127,035	182,052
69 Other Deductions		-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-
71 Interest	4,011	11	2,146	229	(103)	(20)	(29)
72 Schedule "M" Additions	-	-	-	-	-	-	-
73 Schedule "M" Deductions	-	-	-	-	-	-	-
74 Income Before Tax	(26,144,539)	999,858	(13,587,648)	(1,448,750)	650,749	127,055	182,081
75							
76 State Income Taxes	(1,186,962)	45,394	(616,879)	(65,773)	29,544	5,768	8,266
77 Taxable Income	(24,957,577)	954,465	(12,970,768)	(1,382,977)	621,205	121,287	173,815
78							
79 Federal Income Taxes + Other	(5,241,091)	200,438	(2,723,861)	(290,425)	130,453	25,470	36,501
APPROXIMATE PRICE CHANGE	27,030,695	(1,033,077)	14,048,801	1,495,938	(672,921)	(131,384)	(188,285)

Pacificorp
Oregon General Rate Case - December 202·
Tab 4 Adjustment Summary

		4.7	4.8	4.9	4.10	4.11
		Incremental O&M Expense	Paperless Bill Credits Adjustment	Credit Facility Fees Adjustment	Remove Non-Recurring Entries	O&M Expense Escalation
1	Operating Revenues:					
2	General Business Revenues	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-
4	Special Sales	-	-	-	-	-
5	Other Operating Revenues	-	(1,373,862)	-	-	-
6	Total Operating Revenues	-	(1,373,862)	-	-	-
7						
8	Operating Expenses:					
9	Steam Production	-	-	-	-	1,966,987
10	Nuclear Production	-	-	-	-	-
11	Hydro Production	-	-	-	-	120,697
12	Other Power Supply	1,093,227	-	-	192,438	412,328
13	Transmission	23,420	-	-	-	251,660
14	Distribution	4,780,000	-	-	-	546,973
15	Customer Accounting	-	-	-	-	611,281
16	Customer Service & Info	-	-	-	-	103,590
17	Sales	-	-	-	-	-
18	Administrative & General	-	-	412,694	-	1,176,951
19						
20	Total O&M Expenses	5,896,647	-	412,694	192,438	5,190,467
21		-	-	-	-	-
22	Depreciation	-	-	-	-	-
23	Amortization	-	-	-	-	-
24	Taxes Other Than Income	-	-	-	-	-
25	Income Taxes - Federal	(1,182,264)	(275,398)	(82,744)	(38,583)	(1,040,676)
26	Income Taxes - State	(267,750)	(62,370)	(18,739)	(8,738)	(235,684)
27	Income Taxes - Def Net	-	-	-	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-
30						
31	Total Operating Expenses:	4,446,633	(337,769)	311,210	145,117	3,914,106
32						
33	Operating Rev For Return:	(4,446,633)	(1,036,093)	(311,210)	(145,117)	(3,914,106)
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	42,030	(3,193)	2,942	1,372	36,996
45	Weatherization Loans	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-
47						
48	Total Electric Plant:	42,030	(3,193)	2,942	1,372	36,996
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:	42,030	(3,193)	2,942	1,372	36,996
62						
63	Return on Rate Base	-0.120%	-0.028%	-0.008%	-0.004%	-0.105%
64						
65	Return on Equity	-0.224%	-0.052%	-0.016%	-0.007%	-0.197%
66						
67	TAX CALCULATION:					
68	Operating Revenue	(5,896,647)	(1,373,862)	(412,694)	(192,438)	(5,190,467)
69	Other Deductions	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-
71	Interest	932	(71)	65	30	820
72	Schedule "M" Additions	-	-	-	-	-
73	Schedule "M" Deductions	-	-	-	-	-
74	Income Before Tax	(5,897,579)	(1,373,791)	(412,759)	(192,469)	(5,191,287)
75						
76	State Income Taxes	(267,750)	(62,370)	(18,739)	(8,738)	(235,684)
77	Taxable Income	(5,629,829)	(1,311,421)	(394,020)	(183,731)	(4,955,602)
78						
79	Federal Income Taxes + Other	(1,182,264)	(275,398)	(82,744)	(38,583)	(1,040,676)
	APPROXIMATE PRICE CHANGE	6,098,526	1,419,629	426,823	199,027	5,367,620

PacifiCorp
Oregon General Rate Case - December 2021
Miscellaneous General Expense & Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Gain on Property Sales	421	1	(613,406)	SG	26.023%	(159,624)	
Gain on Property Sales	421	1	(105,668)	UT	Situs	-	
Gain on Property Sales	421	1	(62)	WA	Situs	-	
Gain on Property Sales	421	1	3,965,281	SO	27.215%	1,079,164	
Loss on Property Sales	421	1	7,672	SG	26.023%	1,996	
Loss on Property Sales	421	1	196	WYP	Situs	-	
Loss on Property Sales	421	1	81	OR	Situs	81	
Loss on Property Sales	421	1	(7,949)	SO	27.215%	(2,163)	
			3,246,145			919,453	4.1.1
Commercial and Industrial	442	1	1,727,327	OR	Situs	1,727,327	4.1.2
Adjustment to Expense:							
Other Expenses	557	1	(5,165)	SG	26.023%	(1,344)	
Distribution Expense	593	1	(161,609)	OR	Situs	(161,609)	
Customer Records	903	1	(4,389)	CN	31.217%	(1,370)	
Customer Records	903	1	(22,179)	OR	Situs	(22,179)	
Informational Advertising	909	1	(33,143)	CN	31.217%	(10,346)	
Informational Advertising	909	1	(2,290)	CA	Situs	-	
Informational Advertising	909	1	35,790	OR	Situs	35,790	
Informational Advertising	909	1	10,877	ID	Situs	-	
Informational Advertising	909	1	(1,795)	UT	Situs	-	
Informational Advertising	909	1	15,444	WA	Situs	-	
Informational Advertising	909	1	(1,062)	WY	Situs	-	
Administrative & General Salaries	920	1	(1,916)	SO	27.215%	(521)	
Office Supplies and Expense	921	1	(41,446)	SO	27.215%	(11,280)	
Outside Services	923	1	(14,920)	SO	27.215%	(4,061)	
Employee Pensions & Benefits	926	1	(36,529)	SO	27.215%	(9,942)	
Employee Pensions & Benefits	926	1	36,529	WA	Situs	-	
Regulatory Commission Expense	928	1	(10,940)	WY	Situs	-	
Regulatory Commission Expense	928	1	(8,037)	OR	Situs	(8,037)	
Regulatory Commission Expense	928	1	(9,536)	UT	Situs	-	
Regulatory Commission Expense	928	1	(268)	WA	Situs	-	
Regulatory Commission Expense	928	1	28,780	SO	27.215%	7,833	
Duplicate Charages	929	1	(18,115)	SO	27.215%	(4,930)	
Advertising	930	1	531	UT	Situs	-	
Total Miscellaneous General Expense Removal			(245,387)			(191,996)	4.1.1
Total Adjustments			4,728,085			2,454,784	

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 Direct Access Opt Out amortization.

PacifiCorp
Oregon General Rate Case - December 2021
Miscellaneous General Expense & Revenue

Description	FER	Factor	Amt to Exclude	
FERC 421 - (Gain)/Loss on Sale of Utility Plant				
Gain on Property Sales	421	SG	(613,406)	
Gain on Property Sales	421	UT	(105,668)	
Gain on Property Sales	421	WA	(62)	
Gain on Property Sales	421	SO	3,965,281	
Loss on Property Sales	421	SG	7,672	
Loss on Property Sales	421	WYP	196	
Loss on Property Sales	421	OR	81	
Loss on Property Sales	421	SO	(7,949)	
			3,246,145	**Ref 4.1**
FERC 593 - Maintenance of Overhead Lines				
Overtime Charges	593	OR	(161,609)	
Non-Regulated Flights				
Other Expenses	557	SG	(5,165)	
Informational Advertising	909	CN	(1,713)	
Admin & General	920	SO	(1,916)	
Office Supplies and Expenses	921	SO	(24,820)	
			(33,613)	
FERC 909 - Informational & Instructional Advertising				
Blue Sky	909	CN	4,893	
Blue Sky	909	OR	31,489	
Blue Sky	903	CN	(4,389)	
Blue Sky	903	OR	(22,179)	
Blue Sky	929	SO	(18,115)	
DSM	909	CN	(3,848)	
Sponsorships	909	OR	(1,298)	
Sponsorships	909	UT	(4,673)	
Sponsorships	909	ID	(500)	
Campaign	909	UT	(531)	
Campaign	930	UT	531	
Remove system allocation	909	CN	(32,476)	
Remove system allocation	909	OR	(2,057)	
Remove system allocation	909	WA	(367)	
Remove system allocation	909	CA	(2,619)	
Remove system allocation	909	UT	(10,433)	
Remove system allocation	909	WY	(1,508)	
Add situs allocation	909	ID	11,377	
Add situs allocation	909	UT	13,841	
Add situs allocation	909	WY	446	
Add situs allocation	909	WA	15,811	
Add situs allocation	909	CA	329	
Add situs allocation	909	OR	7,655	
			(18,619)	
FERC 921 - Office Supplies & Expenses				
Expense removal	921	SO	(16,626)	
FERC 923 - Outside Services				
Intercompany SERP Costs	923	SO	(14,920)	
FERC 926 - Employee Pensions & Benefits				
Remove system allocation	926	SO	(36,529)	
Add situs allocation	926	WA	36,529	
			-	
FERC 928 - Regulatory Commission Expense				
Remove generation costs from Situs allocation	928	WY	(10,940)	
Remove generation costs from Situs allocation	928	OR	(8,037)	
Remove generation costs from Situs allocation	928	UT	(9,536)	
Remove generation costs from Situs allocation	928	WA	(268)	
Assign generation costs to system allocation	928	SO	28,780	
			-	
TOTAL MISC GENERAL EXPENSE REMOVED			**(245,387)**	**Ref. 4.1**

PacifiCorp
Oregon General Rate Case - December 2021
Miscellaneous General Expense & Revenue

Revenues that need to be included in results:

	Oregon Direct Access Opt Out Amortization	Account	Factor	
Commercial & Industrial	**1,727,327**	**442**	**OR**	**Ref 4.1**

PacifiCorp PAGE 4.2
Oregon General Rate Case - December 2021
Wages & Employee Benefits Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	6,353,682	SG	26.023%	1,653,395	
Fuel Related-Non NPC	501	3	11,559	SE	25.101%	2,902	
Steam Maintenance	512	3	5,677,314	SG	26.023%	1,477,387	
Hydro Operations	535	3	1,263,947	SG-P	26.023%	328,912	
Hydro Operations	535	3	704,104	SG-U	26.023%	183,226	
Hydro Maintenance	545	3	309,517	SG-P	26.023%	80,544	
Hydro Maintenance	545	3	74,125	SG-U	26.023%	19,289	
Other Operations	548	3	1,052,346	SG	26.023%	273,848	
Other Operations	549	3	4,583	OR	Situs	4,583	
Other Maintenance	553	3	295,447	SG	26.023%	76,883	
Other Power Supply Expenses	557	3	3,187,818	SG	26.023%	829,554	
Other Power Supply Expenses	557	3	5,561	ID	Situs	-	
Transmission Operations	560	3	2,041,188	SG	26.023%	531,171	
Transmission Maintenance	571	3	1,573,871	SG	26.023%	409,563	
Distribution Operations	580	3	2,346,241	SNPD	26.756%	627,769	
Distribution Operations	580	3	2,468,152	OR	Situs	713,067	
Distribution Maintenance	593	3	756,231	SNPD	26.756%	202,340	
Distribution Maintenance	593	3	8,536,758	OR	Situs	2,761,651	
Customer Accounts	903	3	3,172,126	CN	31.217%	990,244	
Customer Accounts	903	3	1,807,345	OR	Situs	665,134	
Customer Services	908	3	355,030	CN	31.217%	110,830	
Customer Services	908	3	6,329	OTHER	0.000%	-	
Customer Services	908	3	599,925	OR	Situs	210,297	
Administrative & General	920	3	4,994,728	SO	27.215%	1,359,331	
Administrative & General	920	3	45,940	OR	Situs	8,882	
Administrative & General	935	3	232,131	SO	27.215%	63,175	
Administrative & General	935	3	1,961	OR	Situs	1,523	
			47,877,959			13,585,501	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 2021 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 2021
Wage and Employee Benefit Adjustment

The unadjusted, annualized (12 months ended June 2019), and pro forma period (12 months ending December 2021) 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 2019 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 2019 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 4.2.3.

3. The annualized June 2019 regular time, overtime, and premium pay expenses were then escalated prospectively by labor group to December 2021 (see page 4.2.5). Union and non-union costs were escalated using the contractual and target rates found on page 4.2.4.

4. Compensation related to the Annual Incentive Plan is included on a three-year average of payout percent-tage level. The Annual Incentive Plan is the second step of a two-stage compensation philosophy that provides 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 2021 pension and employee benefit expenses are based on either actuarial projections or are calculated by using actual June 2019 data escalated to December 2021. 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 2021
Wage and Employee Benefit Adjustment

Account	Description	Actual 12 Months Ended June 2019	Pro Forma 12 Months Ending December 2021	Adjustment	Ref.
5001XX	Regular Ordinary Time	425,912,106	464,063,773	38,151,668	
5002XX	Overtime	67,524,548	73,573,153	6,048,605	
5003XX	Premium Pay	9,829,148	10,709,608	880,460	
	Subtotal for Escalation	**503,265,801**	**548,346,533**	**45,080,732**	4.2.3&5
5005XX	Unused Leave Accrual	2,893,590	3,152,787	259,197	4.2.6
500600	Temporary/Contract Labor	18,659	18,659	-	
500700	Severance Pay	542,116	542,116	-	
500850	Other Salary/Labor Costs	3,394,322	3,394,322	-	
50109X	Joint Owner Cutbacks	(1,232,846)	(1,343,279)	(110,434)	4.2.6
	Subtotal Bare Labor	**508,881,641**	**554,111,137**	**45,229,496**	
500410	Annual Incentive Plan	25,306,247	30,371,052	5,064,805	4.2.6
	Total Incentive	**25,306,247**	**30,371,052**	**5,064,805**	
500250	Overtime Meals	1,351,837	1,351,837	-	
500400	Bonus and Awards	5,123,261	5,123,261	-	
501325	Physical Exam	63,284	63,284	-	
502300	Education Assistance	114,172	114,172	-	
580899	Mining Salary/Benefit Credit	(286,077)	(286,077)	-	
	Total Other Labor	**6,366,476**	**6,366,476**	**-**	
	Subtotal Labor and Incentive	**540,554,365**	**590,848,666**	**50,294,301**	
50110X	Pensions	14,800,484	14,034,181	(766,303)	4.2.7
501115	SERP Plan	2,949,199	-	(2,949,199)	4.2.7
50115X	Post Retirement Benefits	(9,828,690)	3,710,284	13,538,974	4.2.7
501160	Post Employment Benefits	6,680,732	7,096,918	416,186	4.2.7
	Total Pensions	**14,601,725**	**24,841,383**	**10,239,658**	4.2.7
501102	Pension Administration	617,175	617,175	-	4.2.7
50112X	Medical	56,328,447	60,182,383	3,853,936	4.2.7
50117X	Dental	3,994,363	4,262,104	267,741	4.2.7
50120X	Vision	351,426	525,307	173,881	4.2.7
50122X	Life	792,177	863,137	70,960	4.2.7
50125X	401(k)	37,766,086	41,519,740	3,753,654	4.2.7
501251	401(k) Administration	840	840	-	4.2.7
501275	Accidental Death & Disability	34,573	37,669	3,097	4.2.7
501300	Long-Term Disability	3,846,486	4,191,040	344,554	4.2.7
5016XX	Worker's Compensation	1,677,515	1,827,780	150,266	4.2.7
502900	Other Salary Overhead	1,301,723	1,301,723	-	4.2.7
	Total Benefits	**106,710,810**	**115,328,899**	**8,618,089**	4.2.7
	Subtotal Pensions and Benefits	**121,312,535**	**140,170,283**	**18,857,748**	4.2.7
580XXX	Payroll Tax Expense	37,611,173	41,182,158	3,570,985	4.2.8
580700	Payroll Tax Expense-Unemployment	2,863,447	2,863,447	-	
	Total Payroll Taxes	**40,474,620**	**44,045,605**	**3,570,985**	
Total Labor		**702,341,520**	**775,064,554**	**72,723,034**	4.2.11
Non-Utility and Capitalized Labor		239,947,739	264,792,814	24,845,075	4.2.11
Total Utility Labor		**462,393,780**	**510,271,740**	**47,877,959**	4.2.11
		Ref. 4.11	Ref. 4.11	Ref. 4.2 Ref. 4.11	

PacifiCorp
Oregon General Rate Case - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended June 2019
Pro Forma: 12 Months Ending December 2021

Labor (12 Months Ended June 2019)

Acct	Account Desc.	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Total	
5001XX	Reg/Ordinary Time	35,130	37,141	32,697	37,128	35,978	33,811	37,941	34,185	34,420	35,938	38,092	33,452	**425,912**	Ref. 4.2.2
5002XX	Overtime	5,657	6,220	6,447	5,463	6,045	5,001	4,783	5,322	7,119	5,046	5,855	4,567	**67,525**	Ref. 4.2.2
5003XX	Premium Pay	812	1,099	859	855	645	709	516	822	750	1,004	919	839	**9,829**	Ref. 4.2.2
Grand Total		**41,599**	**44,460**	**40,003**	**43,446**	**42,668**	**39,521**	**43,240**	**40,329**	**42,288**	**41,987**	**44,866**	**38,859**	**503,266**	Ref. 4.2.2

Labor (12 Months Ended June 2019)

Group Code	Labor Group	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Total	
2	Officer/Exempt	15,280	16,356	14,102	16,324	16,377	14,534	16,574	15,349	16,052	15,437	17,432	14,555	188,371	
3	IBEW 125	3,212	3,350	2,970	3,312	3,207	3,162	3,432	3,207	3,329	3,240	3,328	2,965	38,714	
4	IBEW 659	4,251	4,132	4,131	3,830	3,760	3,690	4,070	4,024	4,526	3,483	3,838	3,334	47,068	
5	UWUA 197	167	180	227	177	198	263	176	165	265	160	179	162	2,317	
8	UWUA 127	4,076	4,331	3,974	4,148	4,645	4,087	4,380	3,763	4,112	4,345	4,848	3,951	50,662	
9	IBEW 57 WY	52	71	66	72	70	64	71	60	61	75	68	59	789	
11	IBEW 57 PD	8,795	10,084	9,107	9,259	8,576	8,352	8,823	8,456	8,191	9,635	9,448	8,671	107,397	
12	IBEW 57 PS	3,647	3,760	3,491	4,117	3,711	3,401	3,524	3,368	3,762	3,548	3,565	3,203	43,098	
13	PCCC Non-Exempt	675	703	645	735	671	660	705	591	593	610	599	548	7,736	
15	IBEW 57 CT	314	334	285	348	341	294	341	287	294	350	320	299	3,807	
16	IBEW 77	125	117	123	117	124	115	107	113	106	122	114	125	1,409	
18	Non-Exempt	1,005	1,040	881	1,007	989	898	1,037	946	997	983	1,128	988	11,898	
Grand Total		**41,599**	**44,460**	**40,003**	**43,446**	**42,668**	**39,521**	**43,240**	**40,329**	**42,288**	**41,987**	**44,866**	**38,859**	**503,266**	Ref. 4.2.2

Annualization Increase

Group Code	Labor Group	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	
2	Officer/Exempt							2.65%						(1)
3	IBEW 125							2.50%						(1)
4	IBEW 659											2.50%		(1)
5	UWUA 197												2.50%	(1)
8	UWUA 127				2.50%									(1)
9	IBEW 57 WY	2.00%												(1)
11	IBEW 57 PD								2.50%					(1)
12	IBEW 57 PS								2.50%					(1)
13	PCCC Non-Exempt							1.73%						(1)
15	IBEW 57 CT								2.50%					(1)
16	IBEW 77								2.25%					(1)
18	Non-Exempt							2.15%						(1)

Annualized Labor June 2019

Group Code	Labor Group	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Total
2	Officer/Exempt	15,685	16,789	14,476	16,756	16,811	14,919	16,574	15,349	16,052	15,437	17,432	14,555	190,835
3	IBEW 125	3,292	3,434	3,045	3,394	3,287	3,241	3,432	3,207	3,329	3,240	3,328	2,965	39,194
4	IBEW 659	4,358	4,235	4,234	3,926	3,854	3,782	4,172	4,124	4,640	3,570	3,838	3,334	48,066
5	UWUA 197	171	184	232	181	203	270	180	170	272	164	183	162	2,371
8	UWUA 127	4,178	4,440	4,074	4,148	4,645	4,087	4,380	3,763	4,112	4,345	4,848	3,951	50,971
9	IBEW 57 WY	52	71	66	72	70	64	71	60	61	75	68	59	789
11	IBEW 57 PD	9,015	10,336	9,334	9,490	8,790	8,561	9,044	8,456	8,191	9,635	9,448	8,671	108,972
12	IBEW 57 PS	3,738	3,854	3,579	4,220	3,804	3,486	3,613	3,368	3,762	3,548	3,565	3,203	43,739
13	PCCC Non-Exempt	687	715	657	748	683	672	705	591	593	610	599	548	7,807
15	IBEW 57 CT	322	342	292	357	350	302	349	287	294	350	320	299	3,863
16	IBEW 77	128	120	126	120	127	118	110	113	106	122	114	125	1,427
18	Non-Exempt	1,026	1,063	900	1,028	1,011	918	1,037	946	997	983	1,128	988	12,023
Grand Total		**42,651**	**45,585**	**41,014**	**44,442**	**43,633**	**40,419**	**43,666**	**40,434**	**42,408**	**42,078**	**44,870**	**38,859**	**510,058**

PacifiCorp
Oregon General Rate Case - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Note: Please see Confidential Exhibit PAC/1304_CONF for redacted information.

Base Period: 12 Months Ended June 2019
Pro Forma: 12 Months Ending December 2021

Pro Forma Increase to December 2021
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
[redacted]													

(1) Overall actual.

[redacted]

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended June 2019
Pro Forma: 12 Months Ending December 2021

Note: Please see Confidential Exhibit PAC/1304_CONF for redacted information.

Pro Forma Labor December 2021

Group Code	Labor Group	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
2	Officer/Exempt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	IBEW 125	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	IBEW 659	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	UWUA 197	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	UWUA 127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	IBEW 57 WY	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	IBEW 57 PD	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	IBEW 57 PS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	PCCC Non-Exempt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	IBEW 57 CT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	IBEW 77	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Non-Exempt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Grand Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**548,347**

Ref. 4.2.2

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Wage and Employee Benefit Adjustment

Note: Please see Confidential Exhibit PAC/1304_CONF for redacted information.

Composite Labor Increases

			Ref.
Regular Time/Overtime/Premium Pay Annualize - Actual	503,265,801		4.2.2
Regular Time/Overtime/Premium Pay December 2021 - Pro Forma	548,346,533	CAGR[1]	4.2.2
% Increase	8.96%	3.49%	

Miscellaneous Bare Labor Escalation

Description	Account	June 2019 Actual	Pro Forma Increase	December 2021 Pro Forma	Pro Forma Adjustment	Ref.
Unused Sick Leave Accrual	5005XX	2,893,590	8.96%	3,152,787	**259,197**	4.2.2
Joint Owner Cutbacks	50109X	(1,232,846)	8.96%	(1,343,279)	**(110,434)**	4.2.2
		1,660,744		1,809,508	148,763	

Annual Incentive Plan Escalation

Description	Account	June 2019 Actual	December 2021 Pro Forma	Pro Forma Adjustment	Ref.
Annual Incentive Plan Compensation	500410	25,306,247	30,371,052	**5,064,805**	4.2.2

Test Year Annual Incentive Plan (AIP) Calculation

	Officer/Exempt Actual Wages	PCCC Non-Exempt Actual Wages	Non-Exempt Actual Wages	Total Wages	Actual AIP	AIP as a % of Wages
Cy 2016	185,205,341	7,807,846	12,038,305	205,051,492	28,666,782	13.98%
Cy 2017	181,127,477	7,449,724	11,798,455	200,375,657	28,897,064	14.42%
Cy 2018	186,311,401	7,854,007	11,664,499	205,829,907	25,783,851	12.53%
3-year Total	552,644,219	23,111,577	35,501,260	611,257,056	83,347,697	13.64%
Test Year	[redacted]				**30,371,052**	13.64%
	Ref 4.2.5	Ref 4.2.5	Ref 4.2.5		Ref 4.2.2	

[1]Compound Annual Growth Rate

PacifiCorp
Oregon General Rate Case - December 2021
Wage and Employee Benefit Adjustment

		A	B	C	D	D - A	
Account	**Description**	**Actual June 2019 Net of Joint Venture**	**Actual June 2019 Gross**	**Projected December 2021 Gross**	**Projected December 2021 Net of Joint Venture**	**Pro Forma Adjustment**	**Ref**
50110X	Pensions	14,800,484	14,917,273	14,144,924	14,034,181	**(766,303)**	**4.2.2**
501115	SERP Plan	2,949,199	2,949,199	-	-	**(2,949,199)**	**4.2.2**
50115X	Post Retirement Benefits	(9,828,690)	(9,781,918)	3,692,628	3,710,284	**13,538,974**	**4.2.2**
501160	Post Employment Benefits	6,680,732	6,902,574	7,332,580	7,096,918	**416,186**	**4.2.2**
	Subtotal	14,601,725	14,987,128	25,170,132	24,841,383	**10,239,658**	**4.2.2**
501102	Pension Administration	617,175	636,442	636,442	617,175	**-**	**4.2.2**
50112X	Medical	56,328,447	58,029,668	62,000,000	60,182,383	**3,853,936**	**4.2.2**
50117X	Dental	3,994,363	4,123,597	4,400,000	4,262,104	**267,741**	**4.2.2**
50120X	Vision	351,426	361,256	540,000	525,307	**173,881**	**4.2.2**
50122X	Life	792,177	819,366	892,762	863,137	**70,960**	**4.2.2**
50125X	401(k)	37,766,086	39,070,727	42,954,053	41,519,740	**3,753,654**	**4.2.2**
501251	401(k) Administration	840	841	841	840	**-**	**4.2.2**
501275	Accidental Death & Disability	34,573	34,861	37,983	37,669	**3,097**	**4.2.2**
501300	Long-Term Disability	3,846,486	3,974,255	4,330,254	4,191,040	**344,554**	**4.2.2**
5016XX	Worker's Compensation	1,677,515	1,729,739	1,884,683	1,827,780	**150,266**	**4.2.2**
502900	Other Salary Overhead	1,301,723	1,302,774	1,302,774	1,301,723	**-**	**4.2.2**
	Subtotal	106,710,810	110,083,526	118,979,792	115,328,899	**8,618,089**	**4.2.2**
	Grand Total	**121,312,535**	125,070,654	144,149,924	**140,170,283**	**18,857,748**	**4.2.2**
		Ref. 4.2.2			Ref. 4.2.2	Ref. 4.2.2	

PacifiCorp
Oregon General Rate Case - December 2021
Wage and Employee Benefit Adjustment
Payroll Tax Adjustment Calculation

FICA Calculated on December 2021 Pro Forma Labor			**Social Security (SS)**	**Medicare**	**Total**	
Pro Forma Wages Adjustment	h		44,970,298	44,970,298		4.2.2
Pro Forma Incentive Adjustment	i		5,064,805	5,064,805		4.2.2
	j	h + i	50,035,103	50,035,103		
Percentage of SS eligible wages	k		91.73%	100.00%		
Total eligible wages	l	j * k	45,894,778	50,035,103		
Tax rate	m		6.20%	1.45%		
Tax on eligible wages	n	l * m	2,845,476	725,509		
Total FICA Tax		n	2,845,476	725,509	**3,570,985**	4.2.2

PacifiCorp
Oregon General Rate Case - December 2021
2020 Protocol FERC Spread

2020P Indicator	Actual 12 Months Ended June 2019	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2021	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2021 Oregon Allocated
500SG	13,461,410	1.917%	1,393,844	14,855,254	26.023%	362,715	3,865,728
502SG	19,112,019	2.721%	1,978,929	21,090,948	26.023%	514,969	5,488,420
503SE	111,639	0.016%	11,559	123,198	25.101%	2,902	30,925
505SG	2,437	0.000%	252	2,690	26.023%	66	700
506SG	28,786,463	4.099%	2,980,657	31,767,120	26.023%	775,645	8,266,641
510SG	3,748,990	0.534%	388,184	4,137,174	26.023%	101,016	1,076,602
511SG	8,727,910	1.243%	903,720	9,631,630	26.023%	235,172	2,506,404
512SG	27,458,737	3.910%	2,843,179	30,301,916	26.023%	739,870	7,885,356
513SG	12,399,234	1.765%	1,283,862	13,683,096	26.023%	334,095	3,560,702
514SG	2,495,258	0.355%	258,368	2,753,626	26.023%	67,234	716,566
535SG-P	4,682,667	0.667%	484,861	5,167,528	26.023%	126,174	1,344,727
535SG-U	1,660,557	0.236%	171,940	1,832,497	26.023%	44,743	476,864
536SG-P	32,637	0.005%	3,379	36,017	26.023%	879	9,372
537SG-P	662,490	0.094%	68,597	731,087	26.023%	17,851	190,248
537SG-U	58,994	0.008%	6,108	65,102	26.023%	1,590	16,941
539SG-P	6,828,515	0.972%	707,050	7,535,565	26.023%	183,993	1,960,952
539SG-U	5,080,514	0.723%	526,055	5,606,569	26.023%	136,893	1,458,977
540SG-P	512	0.000%	53	565	26.023%	14	147
541SG-P	73	0.000%	8	81	26.023%	2	21
542SG-P	295,994	0.042%	30,648	326,642	26.023%	7,975	85,001
542SG-U	13,861	0.002%	1,435	15,296	26.023%	373	3,980
543SG-P	470,039	0.067%	48,670	518,708	26.023%	12,665	134,981
543SG-U	381,043	0.054%	39,455	420,497	26.023%	10,267	109,424
544SG-P	1,250,686	0.178%	129,501	1,380,187	26.023%	33,699	359,161
544SG-U	217,636	0.031%	22,535	240,171	26.023%	5,864	62,499
545SG-P	972,521	0.138%	100,698	1,073,220	26.023%	26,204	279,280
545SG-U	103,342	0.015%	10,700	114,042	26.023%	2,785	29,677
546SG	(121,280)	-0.017%	(12,558)	(133,837)	26.023%	(3,268)	(34,828)
548SG	6,139,285	0.874%	635,684	6,774,969	26.023%	165,422	1,763,025
549OR	44,262	0.006%	4,583	48,845	100.000%	4,583	48,845
549SG	4,145,301	0.590%	429,220	4,574,521	26.023%	111,694	1,190,411
552SG	1,037,918	0.148%	107,470	1,145,388	26.023%	27,966	298,060
553SG	1,718,541	0.245%	177,944	1,896,486	26.023%	46,306	493,515
554SG	96,895	0.014%	10,033	106,928	26.023%	2,611	27,825
556SG	507,745	0.072%	52,574	560,319	26.023%	13,681	145,810
557ID	53,712	0.008%	5,561	59,273	0.000%	-	-
557SG	30,279,431	4.311%	3,135,244	33,414,675	26.023%	815,873	8,695,378
560SG	6,789,975	0.967%	703,059	7,493,034	26.023%	182,954	1,949,885
561SG	10,354,725	1.474%	1,072,166	11,426,891	26.023%	279,006	2,973,578
562SG	1,771,816	0.252%	183,460	1,955,276	26.023%	47,741	508,814
563SG	583,916	0.083%	60,461	644,377	26.023%	15,733	167,684
566SG	65,140	0.009%	6,745	71,885	26.023%	1,755	18,706
567SG	147,727	0.021%	15,296	163,023	26.023%	3,980	42,423
568SG	1,243,672	0.177%	128,774	1,372,446	26.023%	33,510	357,147
569SG	3,236,813	0.461%	335,152	3,571,964	26.023%	87,215	929,519
570SG	7,186,959	1.023%	744,164	7,931,123	26.023%	193,651	2,063,887
571SG	3,504,357	0.499%	362,854	3,867,211	26.023%	94,424	1,006,350
572SG	28,267	0.004%	2,927	31,194	26.023%	762	8,118
580ID	1,202	0.000%	124	1,326	0.000%	-	-
580OR	258,359	0.037%	26,751	285,110	100.000%	26,751	285,110
580SNPD	7,125,836	1.015%	737,835	7,863,672	26.756%	197,418	2,104,034
580UT	374,658	0.053%	38,793	413,452	0.000%	-	-
580WA	101,964	0.015%	10,558	112,522	0.000%	-	-
580WYP	93,887	0.013%	9,721	103,609	0.000%	-	-
581SNPD	12,379,980	1.763%	1,281,869	13,661,849	26.756%	342,982	3,655,416
582CA	32,559	0.005%	3,371	35,931	0.000%	-	-
582ID	398,191	0.057%	41,230	439,421	0.000%	-	-
582OR	340,494	0.048%	35,256	375,750	100.000%	35,256	375,750
582SNPD	3,277	0.000%	339	3,616	26.756%	91	968
582UT	970,520	0.138%	100,491	1,071,011	0.000%	-	-
582WA	98,366	0.014%	10,185	108,551	0.000%	-	-
582WYP	436,380	0.062%	45,184	481,565	0.000%	-	-
583CA	196,788	0.028%	20,376	217,164	0.000%	-	-
583ID	260,045	0.037%	26,926	286,971	0.000%	-	-
583OR	1,304,513	0.186%	135,074	1,439,587	100.000%	135,074	1,439,587
583SNPD	165	0.000%	17	182	26.756%	5	49
583UT	4,336,793	0.617%	449,048	4,785,840	0.000%	-	-
583WA	184,683	0.026%	19,123	203,806	0.000%	-	-
583WYP	349,085	0.050%	36,146	385,231	0.000%	-	-
583WYU	104,858	0.015%	10,857	115,715	0.000%	-	-
585SNPD	208,034	0.030%	21,541	229,575	26.756%	5,763	61,426
586CA	66,432	0.009%	6,879	73,310	0.000%	-	-
586ID	161,401	0.023%	16,712	178,113	0.000%	-	-
586OR	579,652	0.083%	60,019	639,671	100.000%	60,019	639,671
586UT	700,794	0.100%	72,563	773,357	0.000%	-	-
586WA	248,559	0.035%	25,737	274,295	0.000%	-	-
586WYP	285,093	0.041%	29,520	314,613	0.000%	-	-
586WYU	89,734	0.013%	9,291	99,026	0.000%	-	-
587CA	472,414	0.067%	48,916	521,330	0.000%	-	-
587ID	710,539	0.101%	73,572	784,111	0.000%	-	-

PacifiCorp
Oregon General Rate Case - December 2021
2020 Protocol FERC Spread

2020P Indicator	Actual 12 Months Ended June 2019	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2021	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2021 Oregon Allocated
587OR	4,306,255	0.613%	445,886	4,752,140	100.000%	445,886	4,752,140
587UT	3,994,768	0.569%	413,633	4,408,402	0.000%	-	-
587WA	1,021,229	0.145%	105,742	1,126,970	0.000%	-	-
587WYP	867,257	0.123%	89,799	957,056	0.000%	-	-
587WYU	105,851	0.015%	10,960	116,811	0.000%	-	-
588CA	18,519	0.003%	1,918	20,437	0.000%	-	-
588ID	(3,752)	-0.001%	(389)	(4,141)	0.000%	-	-
588OR	16,192	0.002%	1,677	17,868	100.000%	1,677	17,868
588SNPD	2,942,138	0.419%	304,640	3,246,778	26.756%	81,511	868,720
588UT	(91,697)	-0.013%	(9,495)	(101,191)	0.000%	-	-
588WA	(2,896)	0.000%	(300)	(3,196)	0.000%	-	-
588WYP	2,419	0.000%	250	2,669	0.000%	-	-
588WYU	(41,930)	-0.006%	(4,342)	(46,272)	0.000%	-	-
589CA	8,786	0.001%	910	9,695	0.000%	-	-
589ID	11,232	0.002%	1,163	12,395	0.000%	-	-
589OR	81,164	0.012%	8,404	89,568	100.000%	8,404	89,568
589UT	272,483	0.039%	28,214	300,697	0.000%	-	-
589WA	14,361	0.002%	1,487	15,848	0.000%	-	-
589WYP	93,248	0.013%	9,655	102,903	0.000%	-	-
589WYU	5,362	0.001%	555	5,918	0.000%	-	-
590CA	105,593	0.015%	10,934	116,527	0.000%	-	-
590ID	134,688	0.019%	13,946	148,634	0.000%	-	-
590OR	849,596	0.121%	87,970	937,567	100.000%	87,970	937,567
590SNPD	2,445,065	0.348%	253,171	2,698,236	26.756%	67,739	721,950
590UT	1,376,780	0.196%	142,557	1,519,337	0.000%	-	-
590WA	189,439	0.027%	19,615	209,054	0.000%	-	-
590WYP	484,395	0.069%	50,156	534,552	0.000%	-	-
592CA	190,045	0.027%	19,678	209,723	0.000%	-	-
592ID	203,012	0.029%	21,021	224,032	0.000%	-	-
592OR	1,875,579	0.267%	194,204	2,069,783	100.000%	194,204	2,069,783
592SNPD	1,729,019	0.246%	179,029	1,908,048	26.756%	47,902	510,525
592UT	2,250,004	0.320%	232,974	2,482,977	0.000%	-	-
592WA	206,992	0.029%	21,433	228,425	0.000%	-	-
592WYP	709,888	0.101%	73,504	783,392	0.000%	-	-
592WYU	30,006	0.004%	3,107	33,113	0.000%	-	-
593CA	3,448,003	0.491%	357,019	3,805,022	0.000%	-	-
593ID	3,367,055	0.479%	348,637	3,715,693	0.000%	-	-
593OR	19,415,268	2.764%	2,010,329	21,425,596	100.000%	2,010,329	21,425,596
593SNPD	1,094,385	0.156%	113,317	1,207,701	26.756%	30,319	323,137
593UT	22,147,383	3.153%	2,293,222	24,440,605	0.000%	-	-
593WA	3,211,435	0.457%	332,524	3,543,959	0.000%	-	-
593WYP	6,283,331	0.895%	650,599	6,933,930	0.000%	-	-
593WYU	626,614	0.089%	64,882	691,495	0.000%	-	-
594CA	331,646	0.047%	34,340	365,986	0.000%	-	-
594ID	418,411	0.060%	43,324	461,735	0.000%	-	-
594OR	3,669,311	0.522%	379,934	4,049,245	100.000%	379,934	4,049,245
594SNPD	20,194	0.003%	2,091	22,285	26.756%	559	5,963
594UT	7,472,596	1.064%	773,740	8,246,336	0.000%	-	-
594WA	808,165	0.115%	83,680	891,846	0.000%	-	-
594WYP	623,949	0.089%	64,606	688,555	0.000%	-	-
594WYU	100,809	0.014%	10,438	111,247	0.000%	-	-
595SNPD	787,964	0.112%	81,589	869,552	26.756%	21,830	232,661
596CA	66,093	0.009%	6,844	72,936	0.000%	-	-
596ID	73,179	0.010%	7,577	80,757	0.000%	-	-
596OR	618,374	0.088%	64,029	682,403	100.000%	64,029	682,403
596UT	200,415	0.029%	20,752	221,167	0.000%	-	-
596WA	108,699	0.015%	11,255	119,955	0.000%	-	-
596WYP	241,754	0.034%	25,032	266,786	0.000%	-	-
596WYU	39,898	0.006%	4,131	44,029	0.000%	-	-
597CA	16,483	0.002%	1,707	18,190	0.000%	-	-
597ID	33,478	0.005%	3,466	36,944	0.000%	-	-
597OR	200,267	0.029%	20,736	221,003	100.000%	20,736	221,003
597SNPD	(231,006)	-0.033%	(23,919)	(254,926)	26.756%	(6,400)	(68,209)
597UT	188,362	0.027%	19,504	207,866	0.000%	-	-
597WA	25,868	0.004%	2,678	28,547	0.000%	-	-
597WYP	29,749	0.004%	3,080	32,829	0.000%	-	-
597WYU	11,854	0.002%	1,227	13,082	0.000%	-	-
598CA	7,656	0.001%	793	8,449	0.000%	-	-
598OR	42,966	0.006%	4,449	47,415	100.000%	4,449	47,415
598SNPD	1,457,878	0.208%	150,954	1,608,832	26.756%	40,390	430,465
598WA	10,859	0.002%	1,124	11,983	0.000%	-	-
901CN	2,071,551	0.295%	214,496	2,286,047	31.217%	66,959	713,637
902CA	529,531	0.075%	54,830	584,360	0.000%	-	-
902CN	493,516	0.070%	51,100	544,616	31.217%	15,952	170,013
902ID	1,778,805	0.253%	184,184	1,962,989	0.000%	-	-
902OR	5,378,245	0.766%	556,883	5,935,128	100.000%	556,883	5,935,128
902UT	3,504,392	0.499%	362,858	3,867,250	0.000%	-	-
902WA	483,624	0.069%	50,076	533,700	0.000%	-	-
902WYP	823,511	0.117%	85,269	908,780	0.000%	-	-
902WYU	176,923	0.025%	18,319	195,242	0.000%	-	-

PacifiCorp
Oregon General Rate Case - December 2021
2020 Protocol FERC Spread

2020P Indicator	Actual 12 Months Ended June 2019	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2021	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2021 Oregon Allocated
903CA	139,957	0.020%	14,492	154,449	0.000%	-	-
903CN	28,070,562	3.997%	2,906,530	30,977,092	31.217%	907,333	9,670,137
903ID	270,827	0.039%	28,042	298,869	0.000%	-	-
903OR	1,045,460	0.149%	108,251	1,153,711	100.000%	108,251	1,153,711
903UT	2,537,235	0.361%	262,715	2,799,950	0.000%	-	-
903WA	355,965	0.051%	36,858	392,823	0.000%	-	-
903WYP	360,029	0.051%	37,279	397,307	0.000%	-	-
903WYU	70,400	0.010%	7,289	77,689	0.000%	-	-
907CN	(8,828)	-0.001%	(914)	(9,742)	31.217%	(285)	(3,041)
908CA	42,192	0.006%	4,369	46,561	0.000%	-	-
908CN	2,143,251	0.305%	221,920	2,365,171	31.217%	69,277	738,337
908ID	(456)	0.000%	(47)	(503)	0.000%	-	-
908OR	2,030,993	0.289%	210,297	2,241,289	100.000%	210,297	2,241,289
908OTHER	61,125	0.009%	6,329	67,455	0.000%	-	-
908UT	2,429,917	0.346%	251,603	2,681,519	0.000%	-	-
908WA	337,255	0.048%	34,921	372,175	0.000%	-	-
908WYP	954,027	0.136%	98,783	1,052,810	0.000%	-	-
909CN	1,293,631	0.184%	133,947	1,427,579	31.217%	41,814	445,648
910CN	740	0.000%	77	816	31.217%	24	255
920OR	0.48	0.000%	0.05	0.53	100.000%	0.05	0.53
920SO	76,668,180	10.916%	7,938,506	84,606,686	27.215%	2,160,489	23,025,974
921SO	2,052,875	0.292%	212,562	2,265,437	27.215%	57,849	616,546
922SO	(27,605,572)	-3.931%	(2,858,383)	(30,463,955)	27.215%	(777,918)	(8,290,860)
925SO	1,195	0.000%	124	1,319	27.215%	34	359
928CA	165,614	0.024%	17,148	182,762	0.000%	-	-
928ID	35,586	0.005%	3,685	39,271	0.000%	-	-
928OR	85,782	0.012%	8,882	94,664	100.000%	8,882	94,664
928SO	490,819	0.070%	50,821	541,640	27.215%	13,831	147,409
928UT	66,659	0.009%	6,902	73,561	0.000%	-	-
928WA	3,640	0.001%	377	4,016	0.000%	-	-
928WYP	86,394	0.012%	8,946	95,339	0.000%	-	-
929SO	(3,369,621)	-0.480%	(348,903)	(3,718,523)	27.215%	(94,955)	(1,012,008)
935CA	4,037	0.001%	418	4,456	0.000%	-	-
935OR	14,708	0.002%	1,523	16,231	100.000%	1,523	16,231
935SO	2,241,864	0.319%	232,131	2,473,995	27.215%	63,175	673,305
935WA	33	0.000%	3	36	0.000%	-	-
935WYP	164	0.000%	17	181	0.000%	-	-
Utility Labor	**462,393,780**	**65.83603%**	**47,877,959**	**510,271,740**		**13,585,501**	**144,790,996**
						Ref 4.2	
Capital/Non Utility	239,947,739	34.16397%	$ 24,845,075	$ 264,792,814			
Total Labor	**702,341,520**	**100.00%**	**72,723,034**	**775,064,554**			
	Ref 4.2.2		**Ref 4.2.2**	**Ref 4.2.2**			

PacifiCorp
Oregon General Rate Case - December 2021
Revenue-Sensitive Items & Uncollectibles

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Uncollectible Expense	904	3	163,705	OR	Situs	163,705	4.3.1
Other Taxes	408	3	1,106,296	OR	Situs	1,106,296	4.3.1
Regulatory Commission Exp	928	3	178,521	OR	Situs	178,521	4.3.1

Description of Adjustment:

This adjusts the Company's actual June 2019 uncollectible accounts expense to the December 2021 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 and regulatory commission expense based on the normalized level of general business revenues.

PacifiCorp
Oregon General Rate Case - December 2021
Revenue-Sensitive Items & Uncollectibles

Unadjusted Revenue	1,262,527,098	
Normalized Revenue	1,307,157,388	
Adjustments	44,630,291	
Uncollectible Expense in Base Period	4,630,969	
Uncollectible %	0.367%	
Uncollectible Expense	**163,705**	**Ref. 4.3**
Franchise Tax %	2.350%	
Resource Supplier Tax %	0.129%	
Other Tax Expense	**1,106,296**	**Ref. 4.3**
PUC Fees %	0.400%	
PUC Fees Expense	**178,521**	**Ref. 4.3**

PacifiCorp
Oregon General Rate Case - December 2021
Insurance Expense

	ACCOUNT	TYPE	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Base Pd. Inj & Damage	925	1	(13,822,515)	SO	27.215%	(3,761,841)	4.4.1
Remove Base Pd. Inj & Damage	925	1	21,503	OR	Situs	21,503	4.4.1
Adj. Inj & Damage to 5-yr avg.	925	3	1,096,772	OR	Situs	1,096,772	4.4.2
Adjust property damage expense to 10-year average							
Property Insurance - Transmission	924	3	96,958	OR	Situs	96,958	4.4.3
Property Insurance - OR Dist.	924	3	1,697,875	OR	Situs	1,697,875	4.4.3
Property Insurance - Non-T&D	924	3	(260,864)	OR	Situs	(260,864)	4.4.3
Adjust Liability Insurance Premium	925	3	3,547,397	SO	27.215%	965,435	4.4.4
Adjust Property Insurance Premium	924	3	(1,861,030)	SO	27.215%	(506,485)	4.4.4

Description of Adjustment:

This adjustment removes the accrued level of injuries and damages from the base period and recalculates the Oregon-allocated five-year average, using the most recent five-year time period. The adjustment also recalculates the historical 10-year average Oregon-allocated property damage amount using the most recent 10-year time period. 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 2021
Insurance Expense
Injuries and Damages in Unadjusted Results

Amount in Unadjusted Results

G/L Account	Account Title	Allocator	Amount
545050	Inj/Damage Ins Prov	SO	13,785,765
549302	Reimb - Insurance	SO	36,750
		SO	**13,822,515**
			Ref 4.4
545052	Inj/Damage Ins Prov - OR	OR	**(21,503)**
			Ref 4.4

PacifiCorp
Oregon General Rate Case - December 2021
Insurance Expense
Provision for Injuries & Damages
5-Year Average

	Accruals to Injuries & Damages Reserve				Accruals for Insurance Recovery			
	Accruals to Expense	Amount not Seeking Recovery	5 - Year Avg to Recover		Accrual for Ins Recovery	Amount not Seeking Recovery	5 - Year Avg to Recovery	
12 Months Ended June 2015	18,507,160	16,228,767			(15,719,453)	(15,417,329)		
12 Months Ended June 2016	2,674,843	2,456,033			(10,586,667)	(3,586,667)		
12 Months Ended June 2017	1,321,158	(6,783,392)			1,262,587	5,762,587		
12 Months Ended June 2018	4,700,124	(1,234,110)			2,496,412	846,412		
12 Months Ended June 2019	13,729,796	(36,250)			36,750	36,750		
Average Accrual	8,186,616	2,126,210	6,060,407	Below	(4,502,074)	(2,471,649)	(2,030,425)	Below

5 Year Average of Accruals to Injuries & Damages Reserve	6,060,407	Above
5 Year Average of Accruals for Insurance Recovery	(2,030,425)	Above
5 Year Normalized Average	4,029,982	
Oregon SO Allocation %	27.215%	
Oregon Allocated Annual Accrual	**1,096,772**	
	Ref 4.4	

PacifiCorp
Oregon General Rate Case - December 2021
Insurance Expense
Provision for Property Damages
10-Year Average

	Actual Losses			Escalate to 2021		
	System Transmission Losses	Oregon Distribution Losses	System Non-T&D Losses	End CPI-U Index	% Increase	2019
June 2009				215.693		
July 2009 - June 2010	1,156,211	2,372,152	1,597,045	217.965	1.05%	123.878%
July 2010 - June 2011	491,758	5,607,958	1,545,768	225.722	3.56%	122.586%
July 2011 - June 2012	411,470	7,582,565	86,000	229.478	1.66%	118.374%
July 2012 - June 2013	426,385	5,225,455	222,065	233.504	1.75%	116.436%
July 2013 - June 2014	163,517	4,472,174	2,297,475	238.343	2.07%	114.429%
July 2014 - June 2015	489,976	5,264,976	87,189	238.638	0.12%	112.105%
July 2015 - June 2016	440,896	9,217,139	1,272,026	241.018	1.00%	111.967%
July 2016 - June 2017	1,138,848	15,638,087	1,274,291	244.955	1.63%	110.861%
July 2017 - June 2018	1,087,346	2,629,908	39,747	251.989	2.87%	109.079%
July 2018 - June 2019	2,589,430	13,633,167	481,817	256.142	1.65%	106.035%
July 2019 - December 2021				267.196	4.32%	104.315%

	Actual Losses Escalated to CY 2021		
	System Transmission Losses	Oregon Distribution Losses	System Non-T&D Losses
July 2009 - June 2010	1,432,287	2,938,568	1,978,383
July 2010 - June 2011	602,829	6,874,596	1,894,902
July 2011 - June 2012	487,073	8,975,764	101,801
July 2012 - June 2013	496,466	6,084,323	258,564
July 2013 - June 2014	187,110	5,117,449	2,628,970
July 2014 - June 2015	549,290	5,902,326	97,744
July 2015 - June 2016	493,657	10,320,143	1,424,248
July 2016 - June 2017	1,262,541	17,336,576	1,412,695
July 2017 - June 2018	1,186,071	2,868,688	43,355
July 2018 - June 2019	2,745,692	14,455,874	510,893
Total in 2021 $	9,443,017	80,874,309	10,351,556
10 Year Average	944,302	8,087,431	1,035,156
Oregon Allocation Factor	SG	Situs	SG
Oregon Allocation %	26.023%	100%	26.023%
June 2019 - Oregon Allocated 10 Year Average	245,732	8,087,431	269,375
UE - 263 - Oregon Allocated 10 Year Average	148,774	6,389,555	530,239
Adjustment	**96,958**	**1,697,875**	**(260,864)**
	Ref 4.4	**Ref 4.4**	**Ref 4.4**

PacifiCorp
Oregon General Rate Case - December 2021
Insurance Expense
Adjust Base Period Liability Insurance Premium to Expected CY 2019/2020 Level

Adjusting the insurance premium in the base period to the renewed amount effective August 15, 2019 & October 1, 2019

	Premium Renewal 2019/2020	Included in Results 12 Months Ended Jun-19	Adjustment	
Liability Insurance Premium	6,557,841	3,010,444	**3,547,397**	**Ref 4.4**
Property Insurance Premium	3,326,571	5,187,601	**(1,861,030)**	**Ref 4.4**
	9,884,412			

Insurance Renewal 2019/2020

	Policy Effective Date	Policy Limit	Coverage	Self-Insured Retention	Premium Allocated to PacifiCorp Electric	
General Liability Insurance	08/15/2019 - 08/15/2020	505,000,000	Third Party Liability Losses	10,000,000	3,884,841	
California Wildfire Liability Insurance	08/15/2019 - 08/15/2020	95,000,000	Third Party Liability Losses	10,000,000	2,673,000	
Property Insurance	10/1/2019 - 10/1/2020	400,000,000	Property/Boiler Machinery	10,000,000	3,326,571	
					9,884,412	**Above**

PacifiCorp
Oregon General Rate Case - December 2021
Generation Overhaul Expenses

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Generation Overhaul Expense - Steam	510	1	(1,540,376)	SG	26.023%	(400,846)	4.5.1
Generation Overhaul Expense - Other	553	1	1,052,205	SG	26.023%	273,811	4.5.1
			(488,171)			(127,035)	

Description of Adjustment:

This adjustment normalizes generation overhaul expenses in the 12 months ended June 2019 using a four-year average methodology. In this adjustment, overhaul expenses from July 2015 - June 2019 are restated in constant dollars to a June 2019 level using industry specific indices and then those constant dollars are averaged. The actual overhaul costs for the 12 months ended June 2019 are subtracted from the four-year average which results in this adjustment.

PacifiCorp
Oregon General Rate Case - December 2021
Generation Overhaul Expenses

FUNCTION: STEAM

Period	Overhaul Expense	Less Cholla	Overhaul Expense less Cholla	Restate to Constant Dollars (1)	Constant Dollars	
12 Months Ended June 2016	37,637,047	-	37,637,047	6.82%	40,204,935	
12 Months Ended June 2017	25,769,838	-	25,769,838	6.11%	27,343,710	
12 Months Ended June 2018	26,282,886	(3,205,000)	23,077,886	3.45%	23,873,226	
12 Months Ended June 2019	32,510,459	(52,000)	32,458,459	0.00%	32,458,459	
4 Year Average - Steam					30,970,082	
12 Months Ended June 2019 Overhaul Expense - Steam					32,510,459	**Ref. 4.5.2**
Adjustment					**(1,540,376)**	**Ref. 4.5**

FUNCTION: OTHER

Period	Overhaul Expense	Restate to Constant Dollars (1)	Constant Dollars	
12 Months Ended June 2016	3,483,578	5.69%	3,681,837	
12 Months Ended June 2017	939,978	5.06%	987,571	
12 Months Ended June 2018	5,647,997	3.03%	5,818,890	
12 Months Ended June 2019	2,093,159	0.00%	2,093,159	
4 Year Average - Other			3,145,364	
12 Months Ended June 2019 Overhaul Expense - Other			2,093,159	**Ref. 4.5.2**
Adjustment			**1,052,205**	**Ref. 4.5**

Total Adjustment	**(488,171)**	**Ref. 4.5**

(1) Ref. 4.5.3

PacifiCorp
Oregon General Rate Case - December 2021
Generation Overhaul Expenses

Existing Units	12 Mo. Ended June 2016	12 Mo. Ended June 2017	12 Mo. Ended June 2018	12 Mo. Ended June 2019	
Steam Production					
Blundell	1,394,000	(50,000)	248,814	251,321	
Dave Johnston	1,493,146	4,705,191	5,262,270	9,567,670	
Gadsby	-	54,808	70,424	592,107	
Hunter	8,073,225	132,669	8,450,624	6,164,112	
Huntington	6,968,000	-	-	8,850,109	
Jim Bridger	7,135,508	11,305,813	6,745,315	5,927,310	
Naughton	5,297,168	4,644,357	109,439	828	
Wyodak	4,506,000	127,000	-	-	
Cholla(1)	-	-	3,205,000	52,000	
Colstrip	1,069,000	1,352,000	34,000	-	
Craig	1,110,000	3,498,000	819,000	1,105,000	
Hayden	591,000	-	1,338,000	-	
Subtotal - Steam	37,637,047	25,769,838	26,282,886	**32,510,459**	**Ref 4.5.1**
Less Cholla	-	-	(3,205,000)	(52,000)	
Total Steam Production	37,637,047	25,769,838	23,077,886	**32,458,459**	
Other Production					
Hermiston	1,428,000	603,000	1,368,000	2,028,897	
Currant Creek	1,451,455	214,051	9,809	5	
Lake Side	259,095	10,013	3,834,517	(154,086)	
Gadsby Peakers	-	-	-	29,376	
Chehalis	345,028	112,914	435,670	188,968	
Subtotal - Other Production	3,483,578	939,978	5,647,997	**2,093,159**	**Ref 4.5.1**
Grand Total	41,120,625	26,709,816	28,725,883	**34,551,618**	

(1) Overhaul Expense associated with Cholla is removed on Page 4.5.1

PacifiCorp
Oregon General Rate Case - December 2021
Generation Overhaul Expenses

STEAM:	June16	June17	June18	June19
Percentage Change to June 2019	6.82%	6.11%	3.45%	0.00%

OTHER:	June16	June17	June18	June19
Percentage Change to June 2019	5.69%	5.06%	3.03%	0.00%

PacifiCorp
Oregon General Rate Case - December 2021
Memberships & Subscriptions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Total Memberships and Subscriptions							
	930	1	(1,665,097)	SO	27.215%	(453,161)	
	930	1	(34,000)	OR	Situs	(34,000)	
Total			(1,699,097)			(487,161)	4.6.1
Add Back 75% of National & Regional Memberships							
Various	930	1	1,121,094	SO	27.215%	305,109	4.6.2
Total			1,121,094			305,109	

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%. These fees are no longer included in FERC account 930 and are not shown in this adjustment. The fees for these two organizations are now being booked to FERC account 561.

PacifiCorp
Oregon General Rate Case - December 2021
Memberships & Subscriptions

Account	Factor	Description	Amount	
Remove Total Memberships and Subscriptions in Account 930.2				
930.2	SO	Included in Unadjusted Results	(1,665,097)	
930.2	OR	Included in Unadjusted Results	(34,000)	
			(1,699,097)	**Ref 4.6**
Allowed National and Regional Trade Memberships at 75%				
930.2	SO	Albany Area Chamber of Commerce	2,962	
930.2	SO	Albany Downtown Association	180	
930.2	SO	Albany-Millersburg Economic Development Corporation	1,500	
930.2	SO	American Wind Energy Association	25,000	
930.2	SO	American Wind Wildlife Institute	25,000	
930.2	SO	Bay Area Chamber of Commerce	1,511	
930.2	SO	Cannon Beach Chamber of Commerce	310	
930.2	SO	Canyonville Area Chamber of Commerce	75	
930.2	SO	Central Point Chamber of Commerce	250	
930.2	SO	Centre for Energy Advancement through Technological Innovation	29,550	
930.2	SO	Clatsop Economic Development Resources	6,000	
930.2	SO	Coquille Chamber of Commerce	145	
930.2	SO	Corvallis Chamber of Commerce	3,500	
930.2	SO	Cottage Grove Chamber of Commerce	300	
930.2	SO	Creswell Chamber of Commerce	290	
930.2	SO	Dallas Area Visitors Center	600	
930.2	SO	Douglas Timber Operators	600	
930.2	SO	Drive Oregon, Forth	2,500	
930.2	SO	East-Linn Utilities Coordinating Council	125	
930.2	SO	Economic Development Alliance of Lincoln County	100	
930.2	SO	Economic Development for Central Oregon	7,500	
930.2	SO	Edison Electric Institute	871,843	
930.2	SO	Edison Electric Institute - Avian Power Line Interaction Committee	4,500	
930.2	SO	Edison Electric Institute - USWAG	56,618	
930.2	SO	Energy Systems Integration Group	936	
930.2	SO	Friends of Old Town Stayton	2,000	
930.2	SO	Grants Pass Josephine County Chamber of Commerce	1,000	
930.2	SO	Hispanic Metropolitan Chamber	2,000	
930.2	SO	Hood River County Chamber of Commerce	350	
930.2	SO	Intermountain Electrical Association	9,000	
930.2	SO	International Economic Development Council	2,000	
930.2	SO	Jefferson County Economic Development	2,000	
930.2	SO	Klamath Basin Home Builders Association	425	
930.2	SO	Klamath County Chamber of Commerce	799	
930.2	SO	Klamath County Economic Development Association	6,000	
930.2	SO	Klamath Falls Downtown Association	500	
930.2	SO	Lake County Chamber of Commence	1,300	
930.2	SO	Lane Utilities Coordinating Council	100	
930.2	SO	League of Oregon Cities	450	
930.2	SO	Lebanon Area Chamber of Commerce	1,650	
930.2	SO	Linn-Benton Community College Foundation	500	
930.2	SO	Linn-Benton Utilities Coordinating Council	175	
930.2	SO	Madras-Jefferson County Chamber of Commerce	385	
930.2	SO	Mid-Willamette Utility Coordinating Council	52	
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	National Automated Clearing House	2,875	
930.2	SO	National Electric Energy Testing Research and Application Center	98,000	
930.2	SO	National Joint Utilities Notification System	1,313	
930.2	SO	North American Transmission Forum	45,615	
930.2	SO	North American Transmission Forum, Inc.	41,216	
930.2	SO	North Santiam Chamber of Commerce	500	
930.2	SO	Northwest Environmental Business Council	500	
930.2	SO	Northwest Hydroelectric Association	1,200	
930.2	SO	Northwest Public Power Association	1,625	
930.2	SO	Oregon Business Council	54,926	
930.2	SO	Oregon Economic Development Association	17,000	

PacifiCorp
Oregon General Rate Case - December 2021
Memberships & Subscriptions

Account	Factor	Description	Amount	
930.2	SO	Oregon Sports Authority	5,000	
930.2	SO	Oregonians for Food & Shelter, Inc.	2,000	
930.2	SO	Pacific Northwest Utilities Conference Committee	44,032	
930.2	SO	Partners in Diversity	4,000	
930.2	SO	Pendleton Chamber of Commerce	635	
930.2	SO	Philomath Chamber of Commerce	325	
930.2	SO	Portland DAMA International Chapter	700	
930.2	SO	Prineville Chamber of Commerce	240	
930.2	SO	Prineville Economic Development	1,500	
930.2	SO	Redmond Chamber of Commerce	230	
930.2	SO	Redmond Economic Development, Inc.	7,000	
930.2	SO	Redmond Executive Association	700	
930.2	SO	Rocky Mountain Electrical League	18,000	
930.2	SO	Roseburg Area Chamber of Commerce	1,030	
930.2	SO	Rotary Club of Pendleton	435	
930.2	SO	Rotary Club of Roseburg	200	
930.2	SO	Seaside Chamber of Commerce	395	
930.2	SO	Smart Electric Power Alliance	10,250	
930.2	SO	Soul District Business Association	6,000	
930.2	SO	South Coast Development Council, Inc.	5,000	
930.2	SO	Southern Oregon Regional Economic Development	9,000	
930.2	SO	Southern Oregon Timber Industries Association	260	
930.2	SO	Stayton-Sublimity Chamber of Commerce	1,299	
930.2	SO	Strategic Economic Development Corporation	1,400	
930.2	SO	Sutherlin Chamber of Commerce	125	
930.2	SO	Sweet Home Chamber of Commerce	425	
930.2	SO	Takena Kiwanis	260	
930.2	SO	The Enterprise	750	
930.2	SO	Tri-County Chamber of Commerce	255	
930.2	SO	Umatilla Chamber of Commerce	195	
930.2	SO	Umpqua Economic Development Partnership	5,000	
930.2	SO	Umpqua Lions Club	150	
930.2	SO	Utility Economic Development Association, Inc.	745	
930.2	SO	Wallowa County Chamber of Commerce	150	
930.2	SO	Western Energy Institute	500	
930.2	SO	Western Energy Supply Transmission Associates	25,685	
930.2	SO	Western Labor and Management Public Affairs Committee	2,000	
930.2	SO	WorldatWork	265	
			1,494,791	
		Allowed Memberships and Subscriptions - 75% of amount above	**1,121,094**	**Ref 4.6**

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Incremental O&M Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Incremental Repowering O&M Exp.	549	3	[redacted]	SG	26.023%	[redacted]	4.7.1
Overhead & Maintenance - Dist.	593	3	4,780,000	OR	Situs	4,780,000	4.7.2
Overhead & Maintenance - Trans.	571	3	90,000	SG	26.023%	23,420	4.7.2
			4,870,000			4,803,420	
Total Adjustment			[redacted]			[redacted]	

Note: Please see Confidential Exhibit PAC/1305_CONF for redacted information.

Description of Adjustment:

This adjustment adds the incremental operations and maintenance amounts for the new Pryor Mountain wind facility, and wildfire mitigation costs in Oregon. Please refer to direct testimony of Mr. Chad A. Teply for details on the new Pryor Mountain facility, and direct testimony of Mr. David M. Lucas for details on wild fire mitigation costs.

PacifiCorp
Oregon General Rate Case - December 2021
Incremental O&M Expense

Note: Please see Confidential Exhibit PAC/1305_CONF for redacted information.

Project	**Project O&M Amount**	
Pryor Mountain	[redacted]	**Ref 4.7**

PacifiCorp
Oregon General Rate Case - December 2021
Incremental O&M Expense

Fire-Safety Regulations Cost Impacts	**Amount ($)**	
Vegetation Inspections in FHCA zones	400,000	
Vegetation Pole Clearing in FHCA zones	4,000,000	
Distribution Line Inspections in FHCA zones	180,000	
Environmental survey/access in FHCA zones	200,000	
	4,780,000	**Ref 4.7**
Transmission IR / Corona Inspections in FHCA zones	**90,000**	**Ref 4.7**

PacifiCorp
Oregon General Rate Case - December 2021
Paperless Bill Credits Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Misc. Electric Revenue	451	3	(1,373,862)	OR	Situs	(1,373,862)	4.8.1

Description of Adjustment:

This adjustment adds into test period results the reduction in revenues due to paperless billing credits. For details, please refer to the direct testimony of company witness Ms. Melissa S. Nottingham.

PacifiCorp
Oregon General Rate Case - December 2021
Summary of Credits by State

Bill Credits	FERC Acct	Alloc.	Total Co. ($)	
Paperless Credit	451	UT	2,686,268	
	451	**OR**	**1,373,862**	**Ref 4.8**
	451	WA	212,893	
	451	WY	331,568	
	451	ID	216,718	
	451	CA	89,071	
			4,910,381	

PacifiCorp
Oregon General Rate Case - December 2021
Credit Facility Fee Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Credit facility fee expense	921	1	1,516,402	SO	27.215%	412,694	4.9.1

Description of Adjustment:

This adjustment adds the credit facilities and associated commitment fees which are a requirement for the company to have access to short-term borrowing or commercial paper to administrative and general expenses.

PacifiCorp
Oregon General Rate Case - December 2021
Credit Facility Fee Adjustment

Description	FERC Acct	Alloc.	12 ME Jun-19 Total Co. ($)
Add credit facility fees	921	SO	**1,516,402**
			Ref 4.9

Period	Monthly balance ($)
Jul-18	127,630
Aug-18	127,444
Sep-18	128,112
Oct-18	127,630
Nov-18	127,630
Dec-18	130,431
Jan-19	127,630
Feb-19	127,630
Mar-19	106,269
Apr-19	103,217
May-19	108,621
Jun-19	174,160
12 ME Jun-19	1,516,402

PacifiCorp
Oregon General Rate Case - December 2021
Remove Non-Recurring Entries

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Removal of prior-period accounting entry	557	1	739,504	SG	26.023%	192,438	4.10.1

Description of Adjustment:

This adjustment removes priod-period related item. The FERC account 557 entry being removed is related to a CWIP reserve amount originally recorded in December 2017.

PacifiCorp
Oregon General Rate Case - December 2021
Remove Non-Recurring Entries
CWIP Reversal Adjustment

FERC Account	FERC Location	Account Number	Description	Amount	Allocation
557	95	545990	Reversal of CWIP reserve amount originally recorded in December 2017.	(739,504)	SG

PacifiCorp
Oregon General Rate Case - December 2021
O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	87,376	SG	26.023%	22,738	
Steam Operations	500	3	100,774	SG	26.023%	26,224	
Steam Operations	501	3	602,977	SE	25.101%	151,356	
Steam Operations	501	3	115,374	SE	25.101%	28,961	
Steam Operations	501	3	(5,541)	OR	Situs	-	
Steam Operations	502	3	2,266,821	SG	26.023%	589,887	
Steam Operations	502	3	316,628	SG	26.023%	82,395	
Steam Operations	503	3	(4,568)	SE	25.101%	(1,147)	
Steam Operations	505	3	-	SG	26.023%	-	
Steam Operations	505	3	51,825	SG	26.023%	13,486	
Steam Operations	505	3	12,195	SG	26.023%	3,173	
Steam Operations	506	3	(132,312)	SG	26.023%	(34,431)	
Steam Operations	506	3	(64,507)	SG	26.023%	(16,786)	
Steam Operations	506	3	83,387	SG	26.023%	21,699	
Steam Operations	507	3	-	SG	26.023%	-	
Steam Operations	507	3	21,107	SG	26.023%	5,493	
Steam Operations	507	3	-	SG	26.023%	-	
Steam Maintenance	510	3	(53,136)	SG	26.023%	(13,827)	
Steam Maintenance	510	3	55,970	SG	26.023%	14,565	
Steam Maintenance	510	3	93,787	SG	26.023%	24,406	
Steam Maintenance	511	3	495,078	SG	26.023%	128,832	
Steam Maintenance	511	3	127,975	SG	26.023%	33,302	
Steam Maintenance	512	3	-	SG	26.023%	-	
Steam Maintenance	512	3	2,135,253	SG	26.023%	555,649	
Steam Maintenance	512	3	211,825	SG	26.023%	55,123	
Steam Maintenance	513	3	-	SG	26.023%	-	
Steam Maintenance	513	3	779,228	SG	26.023%	202,776	
Steam Maintenance	513	3	30,762	SG	26.023%	8,005	
Steam Maintenance	514	3	216,831	SG	26.023%	56,425	
Steam Maintenance	514	3	54,665	SG	26.023%	14,225	
Hydro Operations	535	3	66,744	SG	26.023%	17,369	
Hydro Operations	535	3	(16,904)	SG	26.023%	(4,399)	
Hydro Operations	536	3	133	SG	26.023%	35	
Hydro Operations	536	3	-	SG	26.023%	-	
Hydro Operations	537	3	68,846	SG	26.023%	17,916	
Hydro Operations	537	3	6,252	SG	26.023%	1,627	
Hydro Operations	539	3	111,047	SG	26.023%	28,897	
Hydro Operations	539	3	43,235	SG	26.023%	11,251	
Hydro Operations	540	3	25,430	SG	26.023%	6,618	
Hydro Operations	540	3	1,085	SG	26.023%	282	
			7,905,641			2,052,123	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2019 to December 2021 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2019 actual data was separated into labor and non-labor components and costs that should not be included in December 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 2021
(cont.) O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Hydro Maintenance	541	3	14	SG	26.023%	4	
Hydro Maintenance	541	3	-	SG	26.023%	-	
Hydro Maintenance	542	3	6,800	SG	26.023%	1,770	
Hydro Maintenance	542	3	439	SG	26.023%	114	
Hydro Maintenance	543	3	16,753	SG	26.023%	4,360	
Hydro Maintenance	543	3	8,841	SG	26.023%	2,301	
Hydro Maintenance	544	3	16,013	SG	26.023%	4,167	
Hydro Maintenance	544	3	2,653	SG	26.023%	690	
Hydro Maintenance	545	3	85,012	SG	26.023%	22,122	
Hydro Maintenance	545	3	21,423	SG	26.023%	5,575	
Other Operations	546	3	11,795	SG	26.023%	3,069	
Other Operations	546	3	-	SG	26.023%	-	
Other Operations	547	3	-	SE	25.101%	-	
Other Operations	547	3	-	SE	25.101%	-	
Other Operations	548	3	336,035	SG	26.023%	87,445	
Other Operations	548	3	-	SG	26.023%	-	
Other Operations	548	3	5,508	SG	26.023%	1,433	
Other Operations	549	3	1,523	OR	Situs	1,523	
Other Operations	549	3	(11)	SG	26.023%	(3)	
Other Operations	549	3	(1,415)	SG	26.023%	(368)	
Other Operations	549	3	29,825	SG	26.023%	7,761	
Other Operations	550	3	8,458	OR	Situs	8,458	
Other Operations	550	3	-	SG	26.023%	-	
Other Operations	550	3	1,160	SG	26.023%	302	
Other Operations	550	3	105,911	SG	26.023%	27,561	
Other Operations	550	3	-	SG	26.023%	-	
Other Maintenance	552	3	-	SG	26.023%	-	
Other Maintenance	552	3	66,481	SG	26.023%	17,300	
Other Maintenance	552	3	1,634	SG	26.023%	425	
Other Maintenance	553	3	27,141	SG	26.023%	7,063	
Other Maintenance	553	3	351,143	SG	26.023%	91,377	
Other Maintenance	553	3	107,385	SG	26.023%	27,944	
Other Maintenance	553	3	8,653	SG	26.023%	2,252	
Other Maintenance	554	3	-	SG	26.023%	-	
Other Maintenance	554	3	34,711	SG	26.023%	9,033	
Other Maintenance	554	3	68,752	SG	26.023%	17,891	
Other Maintenance	554	3	3,508	SG	26.023%	913	
Other Operations	556	3	11,810	SG	26.023%	3,073	
			1,337,955			355,555	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2019 to December 2021 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2019 actual data was separated into labor and non-labor components and costs that should not be included in December 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 2021
(cont.) O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Other Operations	557	3	160,776	OR	Situs	49,407	
Other Operations	557	3	185,994	SG	26.023%	48,400	
Other Operations	557	3	270	SE	25.101%	68	
Other Operations	557	3	-	SG	26.023%	-	
Transmission Operations	560	3	10,717	SG	26.023%	2,789	
Transmission Operations	561	3	206,895	SG	26.023%	53,840	
Transmission Operations	562	3	21,820	SG	26.023%	5,678	
Transmission Operations	563	3	9,752	SG	26.023%	2,538	
Transmission Operations	566	3	60,218	SG	26.023%	15,670	
Transmission Operations	567	3	42,345	SG	26.023%	11,019	
Transmission Maintenance	568	3	3,259	SG	26.023%	848	
Transmission Maintenance	569	3	78,444	SG	26.023%	20,413	
Transmission Maintenance	570	3	142,536	SG	26.023%	37,092	
Transmission Maintenance	571	3	386,201	SG	26.023%	100,500	
Transmission Maintenance	572	3	289	SG	26.023%	75	
Transmission Maintenance	573	3	4,603	SG	26.023%	1,198	
Distribution Operations	580	3	7,802	OR	Situs	1,794	
Distribution Operations	580	3	30,935	SNPD	26.756%	8,277	
Distribution Operations	581	3	-	OR	Situs	-	
Distribution Operations	581	3	(7,298)	SNPD	26.756%	(1,953)	
Distribution Operations	582	3	85,323	OR	Situs	25,258	
Distribution Operations	582	3	14	SNPD	26.756%	4	
Distribution Operations	583	3	83,590	OR	Situs	12,276	
Distribution Operations	583	3	(0)	SNPD	26.756%	(0)	
Distribution Operations	584	3	62	OR	Situs	17	
Distribution Operations	584	3	-	SNPD	26.756%	-	
Distribution Operations	585	3	166	SNPD	26.756%	44	
Distribution Operations	586	3	17,540	OR	Situs	5,750	
Distribution Operations	586	3	-	SNPD	26.756%	-	
Distribution Operations	587	3	117,347	OR	Situs	42,409	
Distribution Operations	587	3	-	SNPD	26.756%	-	
Distribution Operations	588	3	(2,875)	OR	Situs	2,201	
Distribution Operations	588	3	(73,675)	SNPD	26.756%	(19,713)	
Distribution Operations	589	3	83,964	OR	Situs	53,694	
Distribution Operations	589	3	462	SNPD	26.756%	123	
Distribution Maintenance	590	3	8,818	OR	Situs	2,811	
Distribution Maintenance	590	3	1,247	SNPD	26.756%	334	
Distribution Maintenance	591	3	60,991	OR	Situs	12,443	
Distribution Maintenance	591	3	5,132	SNPD	26.756%	1,373	
Distribution Maintenance	592	3	67,409	OR	Situs	21,829	
Distribution Maintenance	592	3	3,529	SNPD	26.756%	944	
			1,804,602			519,452	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2019 to December 2021 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2019 actual data was separated into labor and non-labor components and costs that should not be included in December 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 2021
(cont.) O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Distribution Maintenance	593	3	807,147	OR	Situs	238,384	
Distribution Maintenance	593	3	31,307	SNPD	26.756%	8,377	
Distribution Maintenance	594	3	349,702	OR	Situs	72,798	
Distribution Maintenance	594	3	126	SNPD	26.756%	34	
Distribution Maintenance	595	3	-	OR	Situs	-	
Distribution Maintenance	595	3	4,822	SNPD	26.756%	1,290	
Distribution Maintenance	596	3	44,249	OR	Situs	6,560	
Distribution Maintenance	597	3	3,850	OR	Situs	1,654	
Distribution Maintenance	597	3	(975)	SNPD	26.756%	(261)	
Distribution Maintenance	598	3	48,065	OR	Situs	16,361	
Distribution Maintenance	598	3	118,906	SNPD	26.756%	31,815	
Customer Accounts Operations	901	3	9	OR	Situs	-	
Customer Accounts Operations	901	3	31,784	CN	31.217%	9,922	
Customer Accounts Operations	902	3	195,687	OR	Situs	94,952	
Customer Accounts Operations	902	3	12,868	CN	31.217%	4,017	
Customer Accounts Operations	903	3	93,596	OR	Situs	34,855	
Customer Accounts Operations	903	3	703,068	CN	31.217%	219,477	
Customer Accounts Operations	904	3	691,282	OR	Situs	246,672	
Customer Accounts Operations	904	3	3,309	CN	31.217%	1,033	
Customer Accounts Operations	905	3	21,445	OR	Situs	-	
Customer Accounts Operations	905	3	1,133	CN	31.217%	354	
Customer Service Operations	907	3	358	CN	31.217%	112	
Customer Service Operations	908	3	13,358	OR	Situs	2,606	
Customer Service Operations	908	3	22,227	CN	31.217%	6,939	
Customer Service Operations	908	3	3,315,810	OTHER	0.000%	-	
Customer Service Operations	909	3	177,424	OR	Situs	76,837	
Customer Service Operations	909	3	54,151	CN	31.217%	16,904	
Customer Service Operations	910	3	-	OR	Situs	-	
Customer Service Operations	910	3	614	CN	31.217%	192	
A&G Operations	920	3	(2)	OR	Situs	(2)	
A&G Operations	920	3	(177,447)	SO	27.215%	(48,293)	
A&G Operations	921	3	3,542	CN	31.217%	1,106	
A&G Operations	921	3	10,745	OR	Situs	2,252	
A&G Operations	921	3	340,005	SO	27.215%	92,533	
A&G Operations	922	3	(332,519)	SO	27.215%	(90,496)	
A&G Operations	923	3	71,324	OR	Situs	5,703	
A&G Operations	923	3	965,391	SO	27.215%	262,734	
A&G Operations	924	3	-	SO	27.215%	-	
A&G Operations	925	3	-	SO	27.215%	-	
A&G Operations	926	3	9,708,401	SO	27.215%	2,642,172	
A&G Operations	926	3	(2,604)	OR	Situs	(33,503)	
			17,332,156			3,926,089	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2019 to December 2021 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2019 actual data was separated into labor and non-labor components and costs that should not be included in December 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 2021
(cont.) O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
A&G Operations	928	3	248,082	SG	26.023%	64,557	
A&G Operations	928	3	383	SO	27.215%	104	
A&G Operations	928	3	127,652	SO	27.215%	34,741	
A&G Operations	928	3	684,450	OR	Situs	196,956	
A&G Operations	929	3	(7,861,497)	SO	27.215%	(2,139,531)	
A&G Operations	930	3	264	OR	Situs	(19)	
A&G Operations	930	3	-	CN	31.217%	-	
A&G Operations	930	3	-	SG	26.023%	-	
A&G Operations	930	3	47,237	SO	27.215%	12,856	
A&G Operations	931	3	23,303	OR	Situs	14,370	
A&G Operations	931	3	118,503	SO	27.215%	32,251	
A&G Operations	935	3	9,738	OR	Situs	3,282	
A&G Operations	935	3	1,273	CN	31.217%	397	
A&G Operations	935	3	451,142	SO	27.215%	122,780	
			(6,149,471)			(1,657,255)	
			7,905,641			2,052,123	4.11
			1,337,955			355,555	4.11.1
			1,804,602			519,452	4.11.2
			17,332,156			3,926,089	4.11.3
			(6,149,471)			(1,657,255)	4.11.4
Total Adjustment			22,230,882			5,195,962	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2019 to December 2021 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2019 actual data was separated into labor and non-labor components and costs that should not be included in December 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 2021
O&M Expense Escalation
12 Months Ending December 2021

Function	Allocation Code	Unadjusted O&M	4.1 Miscellaneous General Expense	4.2 Remove Unadjusted Labor	4.3 Revenue Sensitive Items & Uncollectible Expense	4.5 Generation Overhaul Expense	4.6 Membership and Subscriptions	4.9 Credit Facility Fees	4.1 Remove Non-Recurring Entries	8.9 - Remove Rolling Hills	8.1 - Deer Creek Mine	O&M Before Escalation	Escalation Percentages	4.12 O&M Escalation	O&M After Escalation
Steam Operation															
	NPCID	104,388	-	-	-	-	-	-	-	-	-	104,388	0.00%	-	104,388
	NPCSE	719,348,079	-	-	-	-	-	-	-	-	-	719,348,079	0.00%	-	719,348,079
	NPCSSECH	44,335,052	-	-	-	-	-	-	-	-	-	44,335,052	0.00%	-	44,335,052
	NPCWYP	293,720	-	-	-	-	-	-	-	-	-	293,720	0.00%	-	293,720
	SE	23,055,537	-	(111,639)	-	-	-	-	-	-	(8,319,574)	14,624,324	4.09%	598,409	15,222,733
	SG	90,106,906	-	(32,573,429)	-	-	-	-	-	-	(3,233,528)	54,299,948	4.09%	2,221,885	56,521,834
	SNPPS	28,994,797	-	(28,788,901)	-	-	-	-	-	-	-	205,897	4.09%	8,425	214,322
	SSECH	2,819,582	-	-	-	-	-	-	-	-	-	2,819,582	4.09%	115,374	2,934,956
	SSGCH	12,536,619	-	-	-	-	-	-	-	-	-	12,536,619	4.09%	512,983	13,049,601
	CA	(166,735)	-	-	-	-	-	-	-	-	-	(166,735)	4.09%	(6,823)	(173,558)
	OR	1,881,937	-	-	-	-	-	-	-	-	(1,881,937)	-	4.09%	-	0
	WA	(747,862)	-	-	-	-	-	-	-	-	-	(747,862)	4.09%	(30,602)	(778,464)
	WYP	779,191	-	-	-	-	-	-	-	-	-	779,191	4.09%	31,884	811,075
	Steam Operation Total	923,341,210	-	(61,473,969)	-	-	-	-	-	-	(13,435,040)	848,432,202		3,451,535	851,883,737
Steam Maintenance															
	SG	31,860,982	-	(11,223,168)	-	(1,540,376)	-	-	-	-	-	19,097,438	3.45%	658,773	19,756,211
	SNPPS	129,718,509	-	(43,606,960)	-	-	-	-	-	-	-	86,111,548	3.45%	2,970,451	89,081,999
	SSGCH	15,045,883	-	-	-	-	-	-	-	-	-	15,045,883	3.45%	519,014	15,564,897
	Steam Maintenance Total	176,625,373	-	(54,830,128)	-	(1,540,376)	-	-	-	-	-	120,254,869		4,148,238	124,403,107
Hydro Operations															
	SG-P	25,692,173	-	(12,206,823)	-	-	-	-	-	-	-	13,485,350	2.02%	272,200	13,757,550
	SG-U	8,468,048	-	(6,800,064)	-	-	-	-	-	-	-	1,667,983	2.02%	33,668	1,701,652
	Hydro Operations Total	34,160,221	-	(19,006,887)	-	-	-	-	-	-	-	15,153,334		305,868	15,459,202
Hydro Maintenance															
	SG-P	6,496,711	-	(2,989,313)	-	-	-	-	-	-	-	3,507,397	3.55%	124,592	3,631,990
	SG-U	1,654,879	-	(715,881)	-	-	-	-	-	-	-	938,999	3.55%	33,356	972,354
	Hydro Maintenance Total	8,151,590	-	(3,705,194)	-	-	-	-	-	-	-	4,446,396		157,948	4,604,344
Purchased Power															
	NPCSE	11,756	-	-	-	-	-	-	-	-	-	11,756	0.00%	-	11,756
	NPCSG	729,221,964	-	-	-	-	-	-	-	-	-	729,221,964	0.00%	-	729,221,964
	NPCUT	3,755,804	-	-	-	-	-	-	-	-	-	3,755,804	0.00%	-	3,755,804
	OTHER	(69,142,527)	-	-	-	-	-	-	-	-	-	(69,142,527)	0.00%	-	(69,142,527)
	Purchase Power Total	663,846,997	-	-	-	-	-	-	-	-	-	663,846,997		-	663,846,997
Other Operations															
	NPCSE	268,434,763	-	-	-	-	-	-	-	-	-	268,434,763	0.00%	-	268,434,763
	NPCSSECT	1,064,775	-	-	-	-	-	-	-	-	-	1,064,775	0.00%	-	1,064,775
	SG-W	5,086,004	-	(463,447)	-	-	-	-	-	-	-	4,622,557	2.94%	135,736	4,758,293
	SNPPO	21,007,176	-	(9,170,310)	-	-	-	-	-	-	-	11,836,866	2.94%	347,575	12,184,441
	SSGCT	717,121	-	(529,550)	-	-	-	-	-	-	-	187,571	2.94%	5,508	193,079
	SE	9,184	-	-	-	-	-	-	-	-	-	9,184	2.94%	270	9,453
	SG	36,789,163	(5,165)	(30,787,176)	-	-	-	-	739,504	(387)	-	6,735,939	2.94%	197,793	6,933,732
	ID	3,757,166	-	(53,712)	-	-	-	-	-	-	-	3,703,455	2.94%	108,748	3,812,202
	OR	2,066,751	-	(44,262)	-	-	-	-	-	-	-	2,022,489	2.94%	59,388	2,081,877
	UT	24,375	-	-	-	-	-	-	-	-	-	24,375	2.94%	716	25,091
	WYU	64,913	-	-	-	-	-	-	-	-	-	64,913	2.94%	1,906	66,820
	Other Operations Total	339,021,392	(5,165)	(41,048,456)	-	-	-	-	739,504	(387)	-	298,706,888		857,639	299,564,527
Other Maintenance															
	SNPPO	9,324,211	-	(2,584,588)	-	-	-	-	-	-	-	6,739,623	3.60%	242,617	6,982,241
	SSGCT	635,091	-	(251,900)	-	-	-	-	-	-	-	383,190	3.60%	13,794	396,985
	SG	-	-	-	-	1,052,205	-	-	-	(298,253)	-	753,953	3.60%	27,141	781,094
	SG-W	10,735,447	-	(16,866)	-	-	-	-	-	-	-	10,718,581	3.60%	385,855	11,104,435
	Other Maintenance Total	20,694,749	-	(2,853,354)	-	1,052,205	-	-	-	(298,253)	-	18,595,347		669,408	19,264,755
Transmission Operations															
	NPCSE	(1,670,995)	-	-	-	-	-	-	-	-	-	(1,670,995)	0.00%	-	(1,670,995)
	NPCSG	143,000,130	-	-	-	-	-	-	-	-	-	143,000,130	0.00%	-	143,000,130
	SNPT	36,106,956	-	(19,713,299)	-	-	-	-	-	-	-	16,393,657	2.15%	351,746	16,745,403
	Transmission Operations Total	177,436,090	-	(19,713,299)	-	-	-	-	-	-	-	157,722,791		351,746	158,074,538
Transmission Maintenance															
	SNPT	35,357,760	-	(15,200,068)	-	-	-	-	-	-	-	20,157,692	3.05%	615,333	20,773,026
	SG	-	-	-	-	-	-	-	-	-	-	-	3.05%	-	0
	Transmission Maintenance Total	35,357,760	-	(15,200,068)	-	-	-	-	-	-	-	20,157,692		615,333	20,773,026
Distribution Operations															
	CA	1,137,208	-	(795,498)	-	-	-	-	-	-	-	341,709	3.56%	12,157	353,867
	ID	2,084,291	-	(1,538,858)	-	-	-	-	-	-	-	545,433	3.56%	19,405	564,838
	OR	10,917,217	-	(6,886,628)	-	-	-	-	-	-	-	4,030,588	3.56%	143,400	4,173,988
	SNPD	21,271,033	-	(22,659,431)	-	-	-	-	-	-	-	(1,388,398)	3.56%	(49,396)	(1,437,794)
	UT	14,773,376	-	(10,558,319)	-	-	-	-	-	-	-	4,215,056	3.56%	149,963	4,365,020
	WA	2,395,834	-	(1,666,265)	-	-	-	-	-	-	-	729,569	3.56%	25,957	755,526
	WYP	3,172,317	-	(2,127,370)	-	-	-	-	-	-	-	1,044,947	3.56%	37,177	1,082,124
	WYU	395,823	-	(263,876)	-	-	-	-	-	-	-	131,948	3.56%	4,694	136,642
	Distribution Operations Total	56,147,098	-	(46,496,245)	-	-	-	-	-	-	-	9,650,853		343,358	9,994,211

Distribution Maintenance															
	CA	12,037,739	-	(4,165,520)	-	-	-	-	-	-	-	7,872,220	2.84%	223,368	8,095,588
	ID	5,218,968	-	(4,229,824)	-	-	-	-	-	-	-	989,144	2.84%	28,066	1,017,211
	OR	39,973,068	(161,609)	(26,671,361)	-	-	-	-	-	-	-	13,140,098	2.84%	372,839	13,512,937
	SNPD	13,086,663	-	(7,303,497)	-	-	-	-	-	-	-	5,783,166	2.84%	164,093	5,947,258
	UT	56,026,720	-	(33,635,539)	-	-	-	-	-	-	-	22,391,181	2.84%	635,331	23,026,512
	WA	7,297,980	-	(4,561,458)	-	-	-	-	-	-	-	2,736,522	2.84%	77,647	2,814,169
	WYP	9,699,027	-	(8,373,067)	-	-	-	-	-	-	-	1,325,960	2.84%	37,623	1,363,583
	WYU	1,350,334	-	(809,181)	-	-	-	-	-	-	-	541,153	2.84%	15,355	556,508
Distribution Maintenance Total		144,690,499	(161,609)	(89,749,447)	-	-	-	-	-	-	-	54,779,443		1,554,321	56,333,765
Customer Accounts Operations															
	CA	1,569,481	-	(669,488)	-	-	-	-	-	-	-	899,993	5.14%	46,302	946,295
	CN	45,260,144	(4,389)	(30,635,629)	-	-	-	-	-	-	-	14,620,126	5.14%	752,162	15,372,288
	ID	3,292,498	-	(2,049,632)	-	-	-	-	-	-	-	1,242,866	5.14%	63,942	1,306,807
	OR	13,599,956	(22,179)	(6,423,705)	163,705	-	-	-	-	-	-	7,317,776	5.14%	376,478	7,694,254
	UT	12,617,145	-	(6,041,627)	-	-	-	-	-	-	-	6,575,518	5.14%	338,291	6,913,809
	WA	2,842,638	-	(839,589)	-	-	-	-	-	-	-	2,003,049	5.14%	103,051	2,106,100
	WYP	2,555,709	-	(1,183,539)	-	-	-	-	-	-	-	1,372,169	5.14%	70,594	1,442,764
	WYU	312,654	-	(247,323)	-	-	-	-	-	-	-	65,332	5.14%	3,361	68,693
Customer Accounts Operations Total		82,050,225	(26,569)	(48,090,532)	163,705	-	-	-	-	-	-	34,096,829		1,754,181	35,851,011
Customer Service Operations															
	CA	254,680	(2,290)	(42,192)	-	-	-	-	-	-	-	210,198	3.98%	8,367	218,565
	CN	5,405,056	(33,143)	(3,428,794)	-	-	-	-	-	-	-	1,943,119	3.98%	77,350	2,020,469
	ID	177,663	10,877	456	-	-	-	-	-	-	-	188,996	3.98%	7,523	196,519
	OR	3,990,904	35,790	(2,030,993)	-	-	-	-	-	-	-	1,995,701	3.98%	79,443	2,075,144
	OTHER	83,357,915	-	(61,125)	-	-	-	-	-	-	-	83,296,790	3.98%	3,315,810	86,612,600
	UT	4,136,317	(1,795)	(2,429,917)	-	-	-	-	-	-	-	1,704,605	3.98%	67,856	1,772,461
	WA	628,535	15,444	(337,255)	-	-	-	-	-	-	-	306,725	3.98%	12,210	318,935
	WYP	1,338,187	(1,062)	(954,027)	-	-	-	-	-	-	-	383,099	3.98%	15,250	398,349
	WYU	3,320	-	-	-	-	-	-	-	-	-	3,320	3.98%	132	3,452
Customer Service Operations Total		99,292,578	23,821	(9,283,847)	-	-	-	-	-	-	-	90,032,552		3,583,942	93,616,494
A&G Operations & Maintenance															
	920	73,780,526	(1,916)	(76,668,180)	-	-	-	-	-	-	-	(2,889,570)	6.14%	(177,450)	(3,067,020)
	921	9,508,394	(41,446)	(2,052,875)	-	-	-	1,516,402	-	-	-	8,930,476	3.97%	354,292	9,284,768
	922	(33,020,274)	-	27,605,572	-	-	-	-	-	-	-	(5,414,702)	6.14%	(332,519)	(5,747,221)
	923	22,551,561	(14,920)	-	-	-	-	-	-	-	-	22,536,641	4.60%	1,036,715	23,573,356
	924	15,102,464	-	-	-	-	-	-	-	-	-	15,102,464	0.00%	-	15,102,464
	925	17,291,845	-	(1,195)	-	-	-	-	-	-	-	17,290,650	0.00%	-	17,290,650
	926	117,977,451	-	-	-	-	-	-	-	-	-	117,977,451	8.23%	9,705,797	127,683,248
	928	23,130,437	-	(934,493)	178,521	-	-	-	-	-	-	22,374,466	4.74%	1,060,567	23,435,033
	929	(130,126,920)	(18,115)	3,369,621	-	-	-	-	-	(1,240,365)	-	(128,015,780)	6.14%	(7,861,497)	(135,877,276)
	930	2,202,972	531	-	-	-	(578,004)	-	-	-	-	1,625,499	2.92%	47,500	1,673,000
	931	2,558,723	-	-	-	-	-	-	-	-	-	2,558,723	5.54%	141,806	2,700,529
	935	23,743,865	-	(2,260,806)	-	-	-	-	-	-	-	21,483,059	2.15%	462,153	21,945,212
A&G Operations & Maintenance Total		144,701,044	(75,866)	(50,942,356)	178,521	-	(578,004)	1,516,402	-	(1,240,365)	-	93,559,377		4,437,365	97,996,742
	Grand Total	2,905,516,826	(245,387)	(462,393,780)	342,226	(488,171)	(578,004)	1,516,402	739,504	(1,539,005)	(13,435,040)	2,429,435,571		**22,230,882**	2,451,666,453
														Ref 4.11.2	

PacifiCorp
Oregon General Rate Case - December 2021
Escalation Factors

	Escalation Factors June 2019 to December 2021	FERC Accounts
STEAM PRODUCTION PLANT		
Operation:	4.09%	500 - 507
Maintenance:	3.45%	510 - 514
HYDRO PRODUCTION PLANT		
Operation:	2.02%	535 - 540
Maintenance:	3.55%	541 - 545
OTHER PRODUCTION PLANT		
Operation:	2.94%	546 - 550; 556 - 557
Maintenance:	3.60%	551 - 554
TRANSMISSION PLANT		
Operation:	2.15%	560 - 567
Maintenance:	3.05%	568 - 573
DISTRIBUTION PLANT		
Operation:	3.56%	580 - 589
Maintenance:	2.84%	590 - 598
CUSTOMER ACCOUNTS		
Operation:	5.14%	901 - 905
CUSTOMER SERVICE and INFORMATION		
Operation:	3.98%	907 - 910
SALES		
Operation:	4.72%	911 - 916
ADMINISTRATIVE and GENERAL		
Operation:	6.14%	920, 922, 929
Operation:	3.97%	921
Operation:	4.60%	923
Operation:	8.23%	926
Operation:	6.82%	927
Operation:	4.74%	928
Operation:	2.92%	930
Operation:	5.54%	931
Maintenance:	2.15%	935

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Global Insight Escalation Indices
Third Quarter 2019 Forecast
Release Date : November 4, 2019

Note: Please see Confidential Exhibit PAC/1306_CONF for details of escalation factors.

	Calendar years						Global Insight Factors and Percentage Increases June	December	
	2018	2019	2020	2021	2022	2023	2019	2021	FERC Accts
STEAM PRODUCTION PLANT									
Operation: JEFOMS	[redacted]						[redacted]		
%								**4.09%**	500 - 507
Maintenance: JEFMMS	[redacted]						[redacted]		
%								**3.45%**	510 - 514
HYDRO PRODUCTION PLANT									
Operation: JEHOMS	[redacted]						[redacted]		
%								**2.02%**	535 - 540
Maintenance: JEHMMS	[redacted]						[redacted]		
%								**3.55%**	541 - 545
OTHER PRODUCTION PLANT									
Operation: JEOOMS	[redacted]						[redacted]		
%								**2.94%**	546 - 550; 556 - 557
Maintenance: JEOMMS	[redacted]						[redacted]		
%								**3.60%**	551 - 554
TRANSMISSION PLANT									
Operation: JETOMS	[redacted]						[redacted]		
%								**2.15%**	560 - 567
Maintenance: JETMMS	[redacted]						[redacted]		
%								**3.05%**	568 - 573
DISTRIBUTION PLANT									
Operation: JEDOMS	[redacted]						[redacted]		
%								**3.56%**	580 - 589
Maintenance: JEDMMS	[redacted]						[redacted]		
%								**2.84%**	590 - 598
CUSTOMER ACCOUNTS									
Operation: JECAOMS	[redacted]						[redacted]		
%								**5.14%**	901 - 905
CUSTOMER SERVICE and INFORMATION									
Operation: JECSIOMS	[redacted]						[redacted]		
%								**3.98%**	907 - 910
SALES									
Operation: JESALOMS	[redacted]						[redacted]		
%								**4.72%**	911 - 916
ADMINISTRATIVE and GENERAL									
Operation: JEADGOMS	[redacted]						[redacted]		
%								**6.14%**	
Office Supplies 921: JEADG921MS							[redacted]		
%								**3.97%**	921
Outside Services 923: JEADG923MS							[redacted]		
%								**4.60%**	923
Pensions and Benefits 926: JEADG926MS							[redacted]		
%								**8.23%**	926
Franchise Fees 927: JEADG927MS							[redacted]		
%								**6.82%**	927
Regulatory Commission Exp. 928: JEADG928MS							[redacted]		
%								**4.74%**	928
General Advertising 930.1: JEADG9301MS							[redacted]		
%								**2.92%**	930.1
Rents 931: JRENT931							[redacted]		
%								**5.54%**	931
Maintenance									
General Plant 935: JEADG935MS	[redacted]						[redacted]		935
%								**2.15%**	

PacifiCorp
Oregon General Rate Case – December 2021
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 2019 provide the starting point for establishing the adjustment amounts for the December 2021 test period.

5.1 Net Power Costs
5.2 Nodal Pricing Model

Pacificorp
Oregon General Rate Case - December 2021
Tab 5 Adjustment Summary

		5.1	5.2
	Total Adjustments	Net Power Costs	Nodal Pricing Model
1 Operating Revenues:			
2 General Business Revenues	-	-	-
3 Interdepartmental	-	-	-
4 Special Sales	13,472,250	13,472,250	-
5 Other Operating Revenues	-	-	-
6 Total Operating Revenues	13,472,250	13,472,250	-
7			
8 Operating Expenses:			
9 Steam Production	(35,024,379)	(35,024,379)	-
10 Nuclear Production	-	-	-
11 Hydro Production	-	-	-
12 Other Power Supply	(20,239,216)	(20,369,329)	130,113
13 Transmission	(627,267)	(627,267)	-
14 Distribution	-	-	-
15 Customer Accounting	-	-	-
16 Customer Service & Info	-	-	-
17 Sales	-	-	-
18 Administrative & General	-	-	-
19			
20 Total O&M Expenses	(55,890,862)	(56,020,976)	130,113
21		-	-
22 Depreciation	-	-	-
23 Amortization	45,829	-	45,829
24 Taxes Other Than Income	-	-	-
25 Income Taxes - Federal	13,832,769	13,932,664	(99,895)
26 Income Taxes - State	3,132,739	3,155,363	(22,623)
27 Income Taxes - Def Net	74,031	-	74,031
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	-
30			
31 Total Operating Expenses:	(38,805,494)	(38,932,949)	127,455
32			
33 Operating Rev For Return:	52,277,744	52,405,199	(127,455)
34			
35 Rate Base:			
36 Electric Plant In Service	1,040,905	-	1,040,905
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	(367,923)	(367,994)	72
45 Weatherization Loans	-	-	-
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	672,983	(367,994)	1,040,977
49	-	-	-
50 Rate Base Deductions:	-	-	-
51 Accum Prov For Deprec	-	-	-
52 Accum Prov For Amort	-	-	-
53 Accum Def Income Tax	(81,517)	-	(81,517)
54 Unamortized ITC	-	-	-
55 Customer Adv For Const	-	-	-
56 Customer Service Deposits	-	-	-
57 Misc Rate Base Deductions	-	-	-
58		-	-
59 Total Rate Base Deductions	(81,517)	-	(81,517)
60			
61 Total Rate Base:	591,466	(367,994)	959,461
62			
63 Return on Rate Base	1.405%	1.411%	-0.006%
64			
65 Return on Equity	2.625%	2.636%	-0.011%
66			
67 TAX CALCULATION:			
68 Operating Revenue	69,317,284	69,493,226	(175,942)
69 Other Deductions	-	-	-
70 Interest (AFUDC)	-	-	-
71 Interest	13,111	(8,157)	21,268
72 Schedule "M" Additions	45,829	-	45,829
73 Schedule "M" Deductions	346,934	-	346,934
74 Income Before Tax	69,003,068	69,501,383	(498,314)
75			
76 State Income Taxes	3,132,739	3,155,363	(22,623)
77 Taxable Income	65,870,329	66,346,020	(475,691)
78			
79 Federal Income Taxes + Other	13,832,769	13,932,664	(99,895)
APPROXIMATE PRICE CHANGE	(71,598,295)	(71,873,965)	275,669

PacifiCorp
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Net Power Costs

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Sales for Resale (Account 447)							
Existing Firm PPL	447NPC	3	7,542,788	SG	26.023%	1,962,832	5.1.1
Existing Firm UPL	447NPC	3	-	SG	26.023%	-	5.1.1
Post-Merger Firm	447NPC	3	44,227,899	SG	26.023%	11,509,264	5.1.1
Non-Firm	447NPC	3	616	SE	25.101%	155	5.1.1
Total Sales for Resale			51,771,303			13,472,250	
Adjustment to Expense:							
Purchased Power (Account 555)							
Existing Firm Demand PPL	555NPC	3	2,848,086	SG	26.023%	741,147	5.1.1
Existing Firm Demand UPL	555NPC	3	2,484,823	SG	26.023%	646,616	5.1.1
Existing Firm Energy	555NPC	3	15,046,383	SE	25.101%	3,776,866	5.1.1
Post-merger Firm	555NPC	3	(88,348,071)	SG	26.023%	(22,990,494)	5.1.1
Post-merger Firm - Situs	555NPC	3	(3,755,804)	UT	Situs	-	5.1.1
Secondary Purchases	555NPC	3	(11,756)	SE	25.101%	(2,951)	5.1.1
Seasonal Contracts	555NPC	3	-	SG	26.023%	-	5.1.1
Other Generation	555NPC	3	-	SG	26.023%	-	5.1.1
Total Purchased Power Adjustments:			(71,736,339)			(17,828,815)	
Wheeling Expense (Account 565)							
Existing Firm PPL	565NPC	3	21,615,814	SG	26.023%	5,625,004	5.1.1
Existing Firm UPL	565NPC	3	-	SG	26.023%	-	5.1.1
Post-merger Firm	565NPC	3	(28,237,015)	SG	26.023%	(7,348,015)	5.1.1
Non-Firm	565NPC	3	4,365,254	SE	25.101%	1,095,744	5.1.1
Total Wheeling Expense Adjustments:			(2,255,947)			(627,267)	
Fuel Expense (Accounts 501, 503, 547)							
Fuel - Overburden Amortization - Idaho	501NPC	3	(104,388)	ID	Situs	-	5.1.1
Fuel - Overburden Amortization - Wyoming	501NPC	3	(293,720)	WYP	Situs	-	5.1.1
Fuel Consumed - Coal	501NPC	3	(97,457,458)	SE	25.101%	(24,463,272)	5.1.1
Fuel Consumed - Gas	501NPC	3	2,312,395	SE	25.101%	580,445	5.1.1
Steam from Other Sources	503NPC	3	(50,973)	SE	25.101%	(12,795)	5.1.1
Natural Gas Consumed	547NPC	3	34,615,738	SE	25.101%	8,689,065	5.1.1
Simple Cycle Combustion Turbines	547NPC	3	2,656,966	SE	25.101%	666,938	5.1.1
Cholla / APS Exchange	501NPC	3	(44,335,052)	SE	25.101%	(11,128,758)	5.1.1
Total Fuel Expense Adjustments:			(102,656,493)			(25,668,376)	
Total Power Cost Adjustment			(228,420,082)			(57,596,709)	
Post-merger Firm Type 1	555NPC	1	(48,739,448)	SG	26.023%	(12,683,287)	5.1.1
Oregon Situs NPC Adjustments	555NPC	3	786,770	OR	Situs	786,770	5.1.5

Description of Adjustment:

This net power cost adjustment normalizes power costs by adjusting sales for resale, purchased power, wheeling and fuel in a manner consistent with the contractual terms of sales and purchase agreements, and normal hydro and temperature conditions for the 12 month period ending December 2021. The GRID study for this adjustment is based on forecast loads for the test period.

As described in the testimony of Shelley E. McCoy, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; the Company is not requesting recovery of NPC as part of the general rate case.

PacifiCorp
Oregon General Rate Case - December 2021
Net Power Costs

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)
Sales for Resale (Account 447)								
Existing Firm Sales PPL	447.12	-	-	-	-	-	7,542,788	7,542,788
Existing Firm Sales UPL	447.122	-	-	-	-	-	-	-
Post-merger Firm Sales	447.13, .14, .20, .61, .62	229,850,101.48	-	229,850,101	-	229,850,101	274,078,000	44,227,899
Non-firm Sales	447.5	(616)	-	(616)	-	(616)	-	616
Transmission Services	447.9	82,889	(82,889)	-	-	-	-	-
On-system Wholesale Sales	447.1	14,001,706	(14,001,706)	-	-	-	-	-
Total Revenue Adjustments		243,934,081	(14,084,596)	229,849,485	-	229,849,485	281,620,789	51,771,303
Purchased Power (Account 555)								
Existing Firm Demand PPL	555.66	-	-	-	-	-	2,848,086	2,848,086
Existing Firm Demand UPL	555.68	-	-	-	-	-	2,484,823	2,484,823
Existing Firm Energy	555.65, 555.69	-	-	-	-	-	15,046,383	15,046,383
Post-merger Firm	555.26, .55, .59, .61, .62, .63, .64, .67, .8	729,221,964	-	729,221,964	-	729,221,964	592,134,446	(137,087,518)
Post-merger Firm - Situs	555.27	3,755,804	-	3,755,804	-	3,755,804	-	(3,755,804)
Secondary Purchases	555.7, 555.25	11,756	-	11,756	-	11,756	-	(11,756)
NPC Deferral Mechanism	555.57	(69,933,370)	69,933,370	-	-	-	-	-
Seasonal Contracts		-	-	-	-	-	-	-
Wind Integration Charge		-	-	-	-	-	-	-
RPS Compliance Purchases	555.22,555.23,555.24	790,843	(790,843)	-	-	-	-	-
BPA Regional Adjustments	555.11, 555.12, 555.133	-	-	-	-	-	-	-
Post-merger Firm Type 1		-	-	-	(48,739,448)	(48,739,448)	-	48,739,448
Total Purchased Power Adjustment		663,846,997	69,142,527	732,989,524	(48,739,448)	684,250,076	612,513,738	(71,736,339)
Wheeling (Account 565)								
Existing Firm PPL	565.26	-	-	-	-	-	21,615,814	21,615,814
Existing Firm UPL	565.27	-	-	-	-	-	-	-
Post-merger Firm	565.0, 565.46, 565.1	143,000,130	-	143,000,130	-	143,000,130	114,763,115	(28,237,015)
Non-firm	565.25	(1,670,995)	-	(1,670,995)	-	(1,670,995)	2,694,259	4,365,254
Total Wheeling Expense Adjustment		141,329,135	-	141,329,135	-	141,329,135	139,073,187	(2,255,947)
Fuel Expense (Accounts 501, 503 and 547)								
Fuel - Overburden Amortization - Idaho	501.12	104,388	-	104,388	-	104,388	-	(104,388)
Fuel - Overburden Amortization - Wyoming	501.12	293,720	-	293,720	-	293,720	-	(293,720)
Fuel Consumed - Coal	501.1	710,194,823	-	710,194,823	-	710,194,823	612,737,366	(97,457,458)
Fuel Consumed - Gas	501.35	4,582,577	-	4,582,577	-	4,582,577	6,894,972	2,312,395
Steam From Other Sources	503	4,570,678	-	4,570,678	-	4,570,678	4,519,705	(50,973)
Natural Gas Consumed	547.1	268,434,763	-	268,434,763	-	268,434,763	303,050,501	34,615,738
Simple Cycle Combustion Turbines	547.1	1,064,775	-	1,064,775	-	1,064,775	3,721,741	2,656,966
Cholla/APS Exchange	501.1	44,335,052	-	44,335,052	-	44,335,052	-	(44,335,052)
Fuel Regulatory Costs Deferral and Amort	501.15	1,746,531	(1,746,531)	-	-	-	-	-
Fuel Regulatory Costs Deferral and Amort	501.15	7,095,072	(7,095,072)	-	-	-	-	-
Miscellaneous Fuel Costs	501.0, .2, .3, .4, .45, .5, .51	15,960,465	(15,960,465)	-	-	-	-	-
Miscellaneous Fuel Costs - Cholla	501.2,501.45	2,819,582	(2,819,582)	-	-	-	-	-
Total Fuel Expense		1,061,202,426	(27,621,649)	1,033,580,777	-	1,033,580,777	930,924,285	(102,656,493)
Net Power Cost		**1,622,444,476**	**55,605,474**	**1,678,049,950**	**(48,739,448)**	**1,629,310,503**	**1,400,890,421**	**(228,420,082)**
					Ref 5.1		**Ref 5.1.3**	**Ref 5.1**

PacifiCorp
Oregon General Rate Case - December 2021
Net Power Costs

Study Results
MERGED PEAK/ENERGY SPLIT
($)

	Merged 01/21-12/21	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
SPECIAL SALES FOR RESALE					
Pacific Pre Merger	7,542,788	7,542,788			
Post Merger	274,078,000				274,078,000
Utah Pre Merger	-	-			
NonFirm Sub Total	-			-	
TOTAL SPECIAL SALES	281,620,789	7,542,788	-	-	274,078,000
PURCHASED POWER & NET INTERCHANGE					
BPA Peak Purchase	-	-			
Pacific Capacity	-	-	-		
Mid Columbia	2,136,095	640,828	1,495,266		
Misc/Pacific	-	-	-		
Q.F. Contracts/PPL	159,030,641	2,207,257	10,754,080		146,069,303
Small Purchases west	-		-		
Pacific Sub Total	161,166,735	2,848,086	12,249,346	-	146,069,303
Gemstate	1,717,824		1,717,824		
GSLM	-		-		
QF Contracts/UPL	178,524,255	2,484,823	1,064,924		174,974,507
IPP Layoff	-	-	-		
Small Purchases east	14,288		14,288		
UP&L to PP&L	-	-	-		
Utah Sub Total	180,256,367	2,484,823	2,797,036	-	174,974,507
APS Supplemental	-				-
Avoided Cost Resource	-				-
BPA Reserve Purchase					
Cedar Springs Wind	11,723,273				11,723,273
Cedar Springs Wind III	8,908,095				8,908,095
Combine Hills Wind	5,369,183				5,369,183
Cove Mountain Solar	3,863,906				3,863,906
Cove Mountain Solar II	1,378,653				1,378,653
Deseret Purchase	32,857,509				32,857,509
Eagle Mountain - UAMPS/UMPA	2,615,653				2,615,653
Georgia-Pacific Camas	-				-
Hermiston Purchase	-				-
Hunter Solar	7,122,324				7,122,324
Hurricane Purchase	157,969				157,969
MagCorp	-				-
MagCorp Reserves	5,084,680				5,084,680
Milican Solar	2,646,179				2,646,179
Milford Solar	7,081,219				7,081,219
Nucor	7,129,800				7,129,800
Monsanto Reserves	19,999,999				19,999,999
PGE Cove	154,785				154,785
Rock River Wind	3,946,224				3,946,224
Prineville Solar	1,795,505				1,795,505
Sigurd Solar	5,977,024				5,977,024

PacifiCorp
Oregon General Rate Case - December 2021
Net Power Costs

Study Results
MERGED PEAK/ENERGY SPLIT
($)

	Merged 01/21-12/21	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
Three Buttes Wind	20,590,359				20,590,359
Top of the World Wind	40,561,724				40,561,724
BPA So. Idaho	-				-
PSCo Exchange	5,400,000				5,400,000
West Valley Toll	-				-
Seasonal Purchased Power					
Constellation 2013-2016	-				-
Short Term Firm Purchases	66,445,960				66,445,960
New Firm Sub Total	271,090,635	-	-	-	271,090,635
Integration Charge	-				-
Non Firm Sub Total	-			-	
TOTAL PURCHASED PW & NET INT.	612,513,738	5,332,909	15,046,383	-	592,134,446
WHEELING & U. OF F. EXPENSE					
Pacific Firm Wheeling and Use of Facilities	21,615,814	21,615,814			
Utah Firm Wheeling and Use of Facilities	-	-			
Post Merger	114,763,115				114,763,115
Nonfirm Wheeling	2,694,259			2,694,259	
TOTAL WHEELING & U. OF F. EXPENSE	139,073,187	21,615,814	-	2,694,259	114,763,115
THERMAL FUEL BURN EXPENSE					
Carbon	-			-	
Cholla	-			-	
Colstrip	16,438,683			16,438,683	
Craig	17,499,897			17,499,897	
Chehalis	58,131,664			58,131,664	
Currant Creek	58,114,763			58,114,763	
Dave Johnston	48,459,229			48,459,229	
Gadsby	6,894,972			6,894,972	
Gadsby CT	3,721,741			3,721,741	
Hayden	14,769,365			14,769,365	
Hermiston	23,679,545			23,679,545	
Hunter	108,641,852			108,641,852	
Huntington	94,054,145			94,054,145	
Jim Bridger	205,967,584			205,967,584	
Lake Side 1	71,720,629			71,720,629	
Lake Side 2	64,217,107			64,217,107	
Naughton - Gas	27,186,793			27,186,793	
Naughton	78,436,167			78,436,167	
				-	
Wyodak	28,470,445			28,470,445	
TOTAL FUEL BURN EXPENSE	926,404,580	-	-	926,404,580	-
					-

PacifiCorp
Oregon General Rate Case - December 2021
Net Power Costs

Study Results
MERGED PEAK/ENERGY SPLIT
($)

	Merged 01/21-12/21	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
OTHER GENERATION EXPENSE					
Blundell	4,519,705			4,519,705	
TOTAL OTHER GEN. EXPENSE	4,519,705	-	-	4,519,705	-
Settlement Adjustment	-				-
NET POWER COST	1,400,890,421	19,405,934	15,046,383	933,618,543	432,819,560

PacifiCorp
Oregon General Rate Case - December 2021
Net Power Costs
Oregon Situs Adjustments

	Total	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Total Energy Impact	**786,770**	46,881	52,948	61,709	91,296	109,247	121,913	53,653	40,308	47,768	63,211	52,173	45,663

PacifiCorp
Oregon General Rate Case - December 2021
Nodal Pricing Model

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Other Expenses	557	3	500,000	SG	26.023%	130,113	5.2.2
Intangible Plant Amortization	404IP	3	176,111	SG	26.023%	45,829	5.2.1
Adjustment to Rate Base:							
Miscellaneous Intangible Plant	303	3	4,000,000	SG	26.023%	1,040,905	5.2.1
Adjustment to Tax EOP 2020:							
Actual 2020:							
Schedule M Adjustment	SCHMAT	3	7,338	SG	26.023%	1,910	5.2.1
Schedule M Adjustment	SCHMDT	3	1,333,200	SG	26.023%	346,934	5.2.1
Deferred Inc Tax Exp	41010	3	325,984	SG	26.023%	84,830	5.2.1
ADIT Balance - EOP 2020	282	3	(325,984)	SG	26.023%	(84,830)	5.2.1
Annualized 2020:							
Schedule M Adjustment	SCHMAT	3	168,773	SG	26.023%	43,919	5.2.1
Deferred Inc Tax Exp	41110	3	(41,496)	SG	26.023%	(10,798)	5.2.1
ADIT Balance - 2020	282	3	12,732	SG	26.023%	3,313	5.2.1

Description of Adjustment:

This adjustment adds the software related rate base and on-going O&M costs for the Nodal Pricing Model as agreed upon in the Stipulation filed in docket no. UM 1050, PAC/101, Appendix D.

PacifiCorp
Oregon General Rate Case - December 2021
Nodal Pricing Model

December 2020 EOP	
Gross Plant	**Annual Amort.**
4,000,000	176,111
Ref 5.2.2	**Ref 5.2**

2020 Composite Depreciation Rate - Intangible *4.403%*

Adjustments to Tax - 2020

	Book Depreciation	Tax Depreciation	Book-Tax Diff	DIT Expense	Accum. DIT Bal
Actual	7,338	1,333,200	(1,325,862)	325,984	(325,984)
Annualized	168,773			(41,496)	12,732
	Ref 5.2	**Ref 5.2**	**Ref 5.2**	**Ref 5.2**	**Ref 5.2**

MACRS Depreciation Rate (Year 1) *33.330%*

PacifiCorp
Oregon General Rate Case - December 2021
Nodal Pricing Model

Project	Date		Project Capital Amount	
Intangible Plant				
CAISO Implementation Fee	12/31/2020	$	1,000,000	
ESM System Upgrades	12/31/2020	$	906,000	
Settlement System Upgrades	12/31/2020	$	1,585,000	
Internal Capitalized IT Labor	12/31/2020	$	509,000	
		$	**4,000,000**	**Ref 5.2.1**
Incremental O&M				
ESM Maintenance and Licenses		$	200,000	
Settlements Maintenance and Licenses		$	300,000	
		$	**500,000**	**Ref 5.2**

PacifiCorp
Oregon General Rate Case – December 2021
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 Other Plant Closure Costs

Pacificorp
Oregon General Rate Case - December 2021
Tab 6 Adjustment Summary

		Total Adjustments	6.1 Depreciation & Amortiation Expense	6.2 Depreciation & Amortization Reserve	6.3 Depreciation Allocation Correction	6.4 Other Plant Closure Costs
1	Operating Revenues:					
2	General Business Revenues	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-
4	Special Sales	-	-	-	-	-
5	Other Operating Revenues	-	-	-	-	-
6	Total Operating Revenues	-	-	-	-	-
7						
8	Operating Expenses:					
9	Steam Production	3,925,862	286,424	-	-	3,639,439
10	Nuclear Production	-	-	-	-	-
11	Hydro Production	71,612	71,612	-	-	-
12	Other Power Supply	47,561	47,561	-	-	-
13	Transmission	37,762	37,762	-	-	-
14	Distribution	172,798	172,798	-	-	-
15	Customer Accounting	66,448	66,448	-	-	-
16	Customer Service & Info	12,967	12,967	-	-	-
17	Sales	-	-	-	-	-
18	Administrative & General	57,518	57,518	-	-	-
19						
20	Total O&M Expenses	4,392,527	753,088	-	-	3,639,439
21		-	-	-	-	-
22	Depreciation	89,338,517	90,052,912	-	(714,395)	-
23	Amortization	8,409,854	(2,230,703)	-	-	10,640,558
24	Taxes Other Than Income	-	-	-	-	-
25	Income Taxes - Federal	(4,153,371)	(5,275,241)	954,893	143,204	23,772
26	Income Taxes - State	(940,624)	(1,194,696)	216,257	32,432	5,384
27	Income Taxes - Def Net	(18,836,403)	(15,325,438)	-	-	(3,510,965)
28	Investment Tax Credit Adj.	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-
30						
31	Total Operating Expenses:	78,210,500	66,779,921	1,171,150	(538,758)	10,798,188
32						
33	Operating Rev For Return:	(78,210,500)	(66,779,921)	(1,171,150)	538,758	(10,798,188)
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	(7,146,628)	(54,036)	11,070	1,660	(7,105,323)
45	Weatherization Loans	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-
47						
48	Total Electric Plant:	(7,146,628)	(54,036)	11,070	1,660	(7,105,323)
49		-	-	-	-	-
50	Rate Base Deductions:	-	-	-	-	-
51	Accum Prov For Deprec	(205,275,908)	-	(205,275,908)	-	-
52	Accum Prov For Amort	(9,628,577)	-	(9,628,577)	-	-
53	Accum Def Income Tax	5,061,385	3,305,902	-	-	1,755,482
54	Unamortized ITC	-	-	-	-	-
55	Customer Adv For Const	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-
58			-	-	-	-
59	Total Rate Base Deductions	(209,843,100)	3,305,902	(214,904,485)	-	1,755,482
60						
61	Total Rate Base:	(216,989,729)	3,251,867	(214,893,415)	1,660	(5,349,840)
62						
63	Return on Rate Base	-1.668%	-1.803%	0.416%	0.015%	-0.297%
64						
65	Return on Equity	-3.117%	-3.369%	0.778%	0.029%	-0.554%
66						
67	TAX CALCULATION:					
68	Operating Revenue	(102,140,898)	(88,575,297)	-	714,395	(14,279,996)
69	Other Deductions	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-
71	Interest	(4,809,836)	72,081	(4,763,368)	37	(118,586)
72	Schedule "M" Additions	76,612,482	62,332,486	-	-	14,279,996
73	Schedule "M" Deductions	-	-	-	-	-
74	Income Before Tax	(20,718,581)	(26,314,893)	4,763,368	714,358	118,586
75						
76	State Income Taxes	(940,624)	(1,194,696)	216,257	32,432	5,384
77	Taxable Income	(19,777,957)	(25,120,197)	4,547,111	681,926	113,202
78						
79	Federal Income Taxes + Other	(4,153,371)	(5,275,241)	954,893	143,204	23,772
	APPROXIMATE PRICE CHANGE	84,375,616	91,881,793	(21,006,689)	(738,337)	14,238,849

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation & Amortization Expense
Adjustment to Test Period Levels

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Depreciation Expense	403SP	3	16,315,142	SG	26.023%	4,245,629	
Steam Depreciation Expense	403SP	3	8,936,043	SG	26.023%	2,325,394	
Steam Depreciation Expense	403SP	3	83,750,971	SG	26.023%	21,794,208	
Steam Depreciation Expense	403SP	3	10,563,821	SG	26.023%	2,748,984	
Hydro Depreciation Expense	403HP	3	4,314,203	SG	26.023%	1,122,669	
Hydro Depreciation Expense	403HP	3	(77,499)	SG	26.023%	(20,167)	
Hydro Depreciation Expense	403HP	3	(16,253,032)	SG-P	26.023%	(4,229,467)	
Hydro Depreciation Expense	403HP	3	1,307,840	SG-U	26.023%	340,334	
Other Depreciation Expense	403OP	3	-	SG	26.023%	-	
Other Depreciation Expense	403OP	3	(7,833)	SG	26.023%	(2,038)	
Other Depreciation Expense	403OP	3	(33,483,336)	SG-W	26.023%	(8,713,245)	
Other Depreciation Expense	403OP	3	4,752	OR	Situs	4,752	
Other Depreciation Expense	403OP	3	8,056	SG	26.023%	2,096	
Transmission Depreciation Expense	403TP	3	(239,396)	SG	26.023%	(62,297)	
Transmission Depreciation Expense	403TP	3	(213,443)	SG	26.023%	(55,544)	
Transmission Depreciation Expense	403TP	3	8,601,817	SG	26.023%	2,238,419	
Distribution Depreciation Expense	403360	3	391,766	Situs	Situs	38,818	
Distribution Depreciation Expense	403361	3	750,568	Situs	Situs	74,370	
Distribution Depreciation Expense	403362	3	6,301,963	Situs	Situs	624,431	
Distribution Depreciation Expense	403364	3	7,584,724	Situs	Situs	751,534	
Distribution Depreciation Expense	403365	3	4,825,116	Situs	Situs	478,098	
Distribution Depreciation Expense	403366	3	2,393,153	Situs	Situs	237,126	
Distribution Depreciation Expense	403367	3	5,587,115	Situs	Situs	553,600	
Distribution Depreciation Expense	403368	3	8,605,166	Situs	Situs	852,645	
Distribution Depreciation Expense	403369	3	5,152,872	Situs	Situs	510,573	
Distribution Depreciation Expense	403370	3	1,458,137	Situs	Situs	144,480	
Distribution Depreciation Expense	403371	3	54,108	Situs	Situs	5,361	
Distribution Depreciation Expense	403373	3	385,067	Situs	Situs	38,154	
General Depreciation Expense	403GP	3	117,937	CA	Situs	-	
General Depreciation Expense	403GP	3	634,299	OR	Situs	634,299	
General Depreciation Expense	403GP	3	57,846	WA	Situs	-	
General Depreciation Expense	403GP	3	180,533	WYP	Situs	-	
General Depreciation Expense	403GP	3	819,963	UT	Situs	-	
General Depreciation Expense	403GP	3	146,862	ID	Situs	-	
General Depreciation Expense	403GP	3	(25,897)	WYU	Situs	-	
General Depreciation Expense	403GP	3	1,585	SG	26.023%	412	
General Depreciation Expense	403GP	3	(3,584)	SG	26.023%	(933)	
General Depreciation Expense	403GP	3	779,781	SG	26.023%	202,919	
General Depreciation Expense	403GP	3	1,355,444	SO	27.215%	368,888	
General Depreciation Expense	403GP	3	(7,051)	SG	26.023%	(1,835)	
General Depreciation Expense	403GP	3	692	SG	26.023%	180	
General Depreciation Expense	403GP	3	(264,451)	CN	31.217%	(82,554)	
General Depreciation Expense	403GP	3	9,648	SE	25.101%	2,422	
Total Depreciation Expense			130,821,463			27,172,717	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 8.5. The annualized 2020 depreciation and amortization expense for the test period is calculated by applying the currrent composite depreciation and amortization rates to the December 2020 projected plant balances.

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation & Amortization Expense
Adjustment to Test Period Levels

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Intangible Amortization	404IP	3	2,337	CA	Situs	-	
Intangible Amortization	404IP	3	923,235	CN	31.217%	288,207	
Intangible Amortization	404IP	3	(0)	SG	26.023%	(0)	
Intangible Amortization	404IP	3	(78,646)	SG	26.023%	(20,466)	
Intangible Amortization	404IP	3	(8)	ID	Situs	-	
Intangible Amortization	404IP	3	3,397	OR	Situs	3,397	
Intangible Amortization	404IP	3	(1,239)	SE	25.101%	(311)	
Intangible Amortization	404IP	3	(6,762,029)	SG	26.023%	(1,759,658)	
Intangible Amortization	404IP	3	(8,298,775)	SG-P	26.023%	(2,159,560)	
Intangible Amortization	404IP	3	(1,038)	SG-U	26.023%	(270)	
Intangible Amortization	404IP	3	(21,649)	SG	26.023%	(5,634)	
Intangible Amortization	404IP	3	5,449,956	SO	27.215%	1,483,223	
Intangible Amortization	404IP	3	159,758	UT	Situs	-	
Intangible Amortization	404IP	3	-	WA	Situs	-	
Intangible Amortization	404IP	3	(1,935)	WYP	Situs	-	
Intangible Amortization	404IP	3	-	WYU	Situs	-	
Hydro Amortization	404HP	3	-	SG	26.023%	-	
Hydro Amortization	404HP	3	571	SG-P	26.023%	148	
Hydro Amortization	404HP	3	-	SG-U	26.023%	-	
Other Amortization	404OP	3	-	SG	26.023%	-	
General Amortization	404GP	3	(39,046)	CA	Situs	-	
General Amortization	404GP	3	-	CN	31.217%	-	
General Amortization	404GP	3	(58,262)	OR	Situs	(58,262)	
General Amortization	404GP	3	(5,581)	SO	27.215%	(1,519)	
General Amortization	404GP	3	(0)	UT	Situs	-	
General Amortization	404GP	3	(1,526)	WA	Situs	-	
General Amortization	404GP	3	(70,419)	WYP	Situs	-	
General Amortization	404GP	3	-	WYU	Situs	-	
			(8,800,899)			(2,230,703)	6.1.6

Description of Adjustment:

This adjustment reflects the incremental amortization expense that is calculated on the plant additions included in this filing in adjustment 8.5. The annualized 2020 depreciation and amortization expense for the test period is calculated by applying the current composite depreciation and amortization rates to the December 2020 projected plant balances.

PacifiCorp
Oregon General Rate Case - December 2021
Adjustment to Proposed Depreciation Study Rates

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Depreciation Expense	403SP	3	31,447,371	SG	26.023%	8,183,434	
Steam Depreciation Expense	403SP	3	21,351,332	SG	26.023%	5,556,179	
Steam Depreciation Expense	403SP	3	145,174,508	SG	26.023%	37,778,229	
Steam Depreciation Expense	403SP	3	-	SG	26.023%	-	
Hydro Depreciation Expense	403HP	3	(173,879)	SG	26.023%	(45,248)	
Hydro Depreciation Expense	403HP	3	(5,574)	SG	26.023%	(1,451)	
Hydro Depreciation Expense	403HP	3	1,157,626	SG-P	26.023%	301,245	
Hydro Depreciation Expense	403HP	3	354,667	SG-U	26.023%	92,294	
Other Depreciation Expense	403OP	3	-	SG	26.023%	-	
Other Depreciation Expense	403OP	3	10,908,511	SG	26.023%	2,838,682	
Other Depreciation Expense	403OP	3	15,857,743	SG-W	26.023%	4,126,602	
Other Depreciation Expense	403OP	3	1,246	OR	Situs	1,246	
Other Depreciation Expense	403OP	3	974,345	SG	26.023%	253,550	
Transmission Depreciation Expense	403TP	3	541,875	SG	26.023%	141,010	
Transmission Depreciation Expense	403TP	3	761,687	SG	26.023%	198,211	
Transmission Depreciation Expense	403TP	3	7,143,728	SG	26.023%	1,858,986	
Distribution Depreciation Expense	403360	3	(2,431)	Situs	Situs	11,695	
Distribution Depreciation Expense	403361	3	(4,657)	Situs	Situs	22,406	
Distribution Depreciation Expense	403362	3	(39,105)	Situs	Situs	188,123	
Distribution Depreciation Expense	403364	3	(47,065)	Situs	Situs	226,415	
Distribution Depreciation Expense	403365	3	(29,941)	Situs	Situs	144,037	
Distribution Depreciation Expense	403366	3	(14,850)	Situs	Situs	71,439	
Distribution Depreciation Expense	403367	3	(34,670)	Situs	Situs	166,784	
Distribution Depreciation Expense	403368	3	(53,397)	Situs	Situs	256,877	
Distribution Depreciation Expense	403369	3	(31,975)	Situs	Situs	153,821	
Distribution Depreciation Expense	403370	3	(9,048)	Situs	Situs	43,528	
Distribution Depreciation Expense	403371	3	(336)	Situs	Situs	1,615	
Distribution Depreciation Expense	403373	3	(2,389)	Situs	Situs	11,495	
General Depreciation Expense	403GP	3	12,156	CA	Situs	-	
General Depreciation Expense	403GP	3	81,861	OR	Situs	81,861	
General Depreciation Expense	403GP	3	(52,264)	WA	Situs	-	
General Depreciation Expense	403GP	3	67,823	WYP	Situs	-	
General Depreciation Expense	403GP	3	528,150	UT	Situs	-	
General Depreciation Expense	403GP	3	24,683	ID	Situs	-	
General Depreciation Expense	403GP	3	22,602	WYU	Situs	-	
General Depreciation Expense	403GP	3	(4,705)	SG	26.023%	(1,224)	
General Depreciation Expense	403GP	3	7,676	SG	26.023%	1,997	
General Depreciation Expense	403GP	3	(246,175)	SG	26.023%	(64,061)	
General Depreciation Expense	403GP	3	938,485	SO	27.215%	255,412	
General Depreciation Expense	403GP	3	-	SG	26.023%	-	
General Depreciation Expense	403GP	3	-	SG	26.023%	-	
General Depreciation Expense	403GP	3	70,117	CN	31.217%	21,888	
General Depreciation Expense	403GP	3	12,426	SE	25.101%	3,119	
Total Depreciation Expense			236,688,153			62,880,195	6.1.6

Description of Adjustment:

This adjustment reflects the incremental depreciation expense for the proposed depreciation study rates. The depreciation expense is calculated by applying the proposed composite depreciation rates to the December 2020 projected plant balances. The Company's application to implement revised depreciation rates is in Docket No. UM-1968. This adjustment is subject to change depending on the outcome of that docket.

PacifiCorp
Oregon General Rate Case - December 2021
Vehicle Depreciation Expense - Adjustment to Proposed Depreciation Rates

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	255,040	SG	26.023%	66,368	
Fuel Related-Non NPC	501	3	464	SE	25.101%	116	
Steam Maintenance	512	3	227,890	SG	26.023%	59,303	
Hydro Operations	535	3	50,735	SG-P	26.023%	13,203	
Hydro Operations	535	3	28,263	SG-U	26.023%	7,355	
Hydro Maintenance	545	3	12,424	SG-P	26.023%	3,233	
Hydro Maintenance	545	3	2,975	SG-U	26.023%	774	
Other Operations	548	3	42,242	SG	26.023%	10,992	
Other Operations	549	3	184	Situs	Situs	184	
Other Maintenance	553	3	11,859	SG	26.023%	3,086	
Other Power Supply Expenses	557	3	127,961	SG	26.023%	33,299	
Other Power Supply Expenses	557	3	223	Situs	Situs	-	
Transmission Operations	560	3	81,934	SG	26.023%	21,321	
Transmission Maintenance	571	3	63,176	SG	26.023%	16,440	
Distribution Operations	580	3	94,179	SNPD	26.756%	25,199	
Distribution Operations	580	3	99,073	Situs	Situs	28,623	
Distribution Maintenance	593	3	30,355	SNPD	26.756%	8,122	
Distribution Maintenance	593	3	342,670	Situs	Situs	110,854	
Customer Accounts	903	3	127,331	CN	31.217%	39,749	
Customer Accounts	903	3	72,548	Situs	Situs	26,699	
Customer Services	908	3	14,251	CN	31.217%	4,449	
Customer Services	908	3	254	OTHER	0.000%	-	
Customer Services	908	3	24,081	Situs	Situs	8,441	
Administrative & General	920	3	200,491	SO	27.215%	54,564	
Administrative & General	920	3	1,844	Situs	Situs	357	
Administrative & General	935	3	9,318	SO	27.215%	2,536	
Administrative & General	935	3	79	Situs	Situs	61	
			1,921,846			545,329	6.1.17
Customer Services	910	3	246	CN	31.217%	77	
Fuel Related - Non-NPC	501	3	152,467	SE	25.101%	38,271	
Steam Operations	506	3	470,224	SG	26.023%	122,365	
Hydro Operations	535	3	130,310	SG-P	26.023%	33,910	
Hydro Operations	535	3	50,482	SG-U	26.023%	13,137	
			803,728			207,760	6.1.17
Total Vehicle Depreciation			2,725,574			753,088	
Adjustment to Tax:							
Accumulated Def Inc Tax Balance	282	3	(58,226)	CA	Situs	-	
Accumulated Def Inc Tax Balance	282	3	(154,102)	ID	Situs	-	
Accumulated Def Inc Tax Balance	282	3	(787,720)	UT	Situs	-	
Accumulated Def Inc Tax Balance	282	3	(127,985)	WA	Situs	-	
Accumulated Def Inc Tax Balance	282	3	(250,607)	WYP	Situs	-	
Accumulated Def Inc Tax Balance	282	3	(51,024)	WYU	Situs	-	
Accumulated Def Inc Tax Balance	282	3	(594,083)	OR	Situs	(594,083)	
Accumulated Def Inc Tax Balance	282	3	(6,501)	SE	25.101%	(1,632)	
Accumulated Def Inc Tax Balance	282	3	(1,262,064)	SG	26.023%	(328,422)	
Accumulated Def Inc Tax Balance	282	3	(116,512)	SO	27.215%	(31,709)	
			(3,408,824)			(955,847)	

Description of Adjustment:

This adjustment reflects the incremental depreciation expense for the proposed depreciation study rates for vehicles. The Company's application to implement revised depreciation rates is in Docket No. UM-1968. This adjustment is subject to change depending on the outcome of that docket.

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation & Amortization Expense
Tax Impacts

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	19,398	CA	Situs	-	
Schedule M Adjustment	SCHMAT	3	7,544	CN	31.217%	2,355	
Schedule M Adjustment	SCHMAT	3	31,626,078	SG	26.023%	8,229,938	
Schedule M Adjustment	SCHMAT	3	21,835,696	SG	26.023%	5,682,223	
Schedule M Adjustment	SCHMAT	3	(761,473)	ID	Situs	-	
Schedule M Adjustment	SCHMAT	3	(633,177)	OR	Situs	(633,177)	
Schedule M Adjustment	SCHMAT	3	(26,180)	SE	25.101%	(6,572)	
Schedule M Adjustment	SCHMAT	3	186,239,669	SG	26.023%	48,464,465	
Schedule M Adjustment	SCHMAT	3	1,336,526	SO	27.215%	363,740	
Schedule M Adjustment	SCHMAT	3	(620,959)	UT	Situs	-	
Schedule M Adjustment	SCHMAT	3	(638,546)	WA	Situs	-	
Schedule M Adjustment	SCHMAT	3	(2,655,497)	WYP	Situs	-	
Schedule M Adjustment	SCHMAT	3	(90,593)	SG	26.023%	(23,575)	
Schedule M Adjustment	SCHMAT	3	972,570	SG	26.023%	253,088	
			236,611,056			62,332,486	
Deferred Income Tax Expense	41110	3	(4,770)	CA	Situs	-	
Deferred Income Tax Expense	41110	3	(1,855)	CN	31.217%	(579)	
Deferred Income Tax Expense	41110	3	(7,775,777)	SG	26.023%	(2,023,462)	
Deferred Income Tax Expense	41110	3	(5,368,655)	SG	26.023%	(1,397,065)	
Deferred Income Tax Expense	41110	3	187,220	ID	Situs	-	
Deferred Income Tax Expense	41110	3	155,677	OR	Situs	155,677	
Deferred Income Tax Expense	41110	3	6,437	SE	25.101%	1,616	
Deferred Income Tax Expense	41110	3	(45,790,003)	SG	26.023%	(11,915,764)	
Deferred Income Tax Expense	41110	3	(328,606)	SO	27.215%	(89,431)	
Deferred Income Tax Expense	41110	3	152,673	UT	Situs	-	
Deferred Income Tax Expense	41110	3	156,997	WA	Situs	-	
Deferred Income Tax Expense	41110	3	652,897	WYP	Situs	-	
Deferred Income Tax Expense	41110	3	22,274	SG	26.023%	5,796	
Deferred Income Tax Expense	41110	3	(239,122)	SG	26.023%	(62,226)	
			(58,174,613)			(15,325,438)	
Accumulated Def Inc Tax Balance	282	3	569	CN	31.217%	178	
Accumulated Def Inc Tax Balance	282	3	(47,632)	OR	Situs	(47,632)	
Accumulated Def Inc Tax Balance	282	3	(1,968)	SE	25.101%	(494)	
Accumulated Def Inc Tax Balance	282	3	16,456,188	SG	26.023%	4,282,333	
Accumulated Def Inc Tax Balance	282	3	100,546	SO	27.215%	27,364	
			16,507,703			4,261,749	

Description of Adjustment:

This adjustment includes the associated tax impacts.

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation and Amortization Expense Summary

Description	Account	Factor	12 ME Jun 2019 Expense	Annualized Existing Rates Dec 2020 Expense	Adjustment to Test Period	Proposed Rates Dec 2020 Expense	Adjustment to Proposed Depreciation Rates
DEPRECIATION EXPENSE							
Steam Production Plant:							
Pre-merger Pacific	403SP	SG	30,169,736	46,484,878	16,315,142	77,932,249	31,447,371
Pre-merger Utah	403SP	SG	30,130,900	39,066,942	8,936,043	60,418,274	21,351,332
Post-merger	403SP	SG	161,917,762	245,668,733	83,750,971	390,843,241	145,174,508
Post-merger - Cholla	403SP	SG	15,145,184	25,709,005	10,563,821	25,709,005	-
Total Steam Plant			237,363,582	356,929,558	119,565,977	554,902,768	197,973,210
Hydro Production Plant:							
Pre-merger Pacific	403HP	SG	(74,556)	4,239,647	4,314,203	4,065,768	(173,879)
Pre-merger Utah	403HP	SG	1,386,317	1,308,818	(77,499)	1,303,244	(5,574)
Post-merger	403HP	SG-P	32,771,109	16,518,077	(16,253,032)	17,675,703	1,157,626
Post-merger	403HP	SG-U	5,700,987	7,008,828	1,307,840	7,363,494	354,667
Total Hydro Plant			39,783,857	29,075,369	(10,708,489)	30,408,208	1,332,840
Other Production Plant:							
Pre-merger Utah	403OP	SG	-	-	-	-	-
Post-merger	403OP	SG	57,519,990	57,512,156	(7,833)	68,420,667	10,908,511
Post-merger Wind	403OP	SG-W	67,675,190	34,191,854	(33,483,336)	50,049,597	15,857,743
Black Cap Solar	403OP	OR	-	4,752	4,752	5,998	1,246
Post-merger	403OP	SG	3,259,020	3,267,075	8,056	4,241,421	974,345
Total Other Production Plant			128,454,199	94,975,837	(33,478,362)	122,717,683	27,741,846
Transmission Plant:							
Pre-merger Pacific	403TP	SG	8,665,935	8,426,538	(239,396)	8,968,413	541,875
Pre-merger Utah	403TP	SG	10,823,573	10,610,129	(213,443)	11,371,816	761,687
Post-merger	403TP	SG	91,403,582	100,005,399	8,601,817	107,149,127	7,143,728
Total Transmission Plant			110,893,089	119,042,066	8,148,978	127,489,357	8,447,290
Distribution Plant:							
California	403364	CA	7,937,175	8,373,979	436,804	8,373,979	-
Oregon	403364	OR	53,608,264	57,917,455	4,309,191	59,215,689	1,298,234
Washington	403364	WA	14,311,535	15,219,815	908,280	15,101,449	(118,366)
Eastern Wyoming	403364	WYP	16,472,691	20,083,504	3,610,813	18,945,115	(1,138,389)
Utah	403364	UT	54,969,349	85,435,788	30,466,439	85,711,083	275,296
Idaho	403364	ID	7,065,187	10,576,685	3,511,499	10,272,310	(304,376)
Western Wyoming	403364	WYU	3,841,152	4,087,882	246,730	3,805,617	(282,265)
Total Distribution Plant			158,205,353	201,695,108	43,489,755	201,425,242	(269,866)
General Plant:							
California	403GP	CA	402,578	520,515	117,937	532,670	12,156
Oregon	403GP	OR	5,078,614	5,712,913	634,299	5,794,774	81,861
Washington	403GP	WA	1,153,845	1,211,691	57,846	1,159,427	(52,264)
Eastern Wyoming	403GP	WYP	2,030,031	2,210,564	180,533	2,278,387	67,823
Utah	403GP	UT	4,800,293	5,620,256	819,963	6,148,405	528,150
Idaho	403GP	ID	919,901	1,066,763	146,862	1,091,446	24,683
Western Wyoming	403GP	WYU	388,208	362,311	(25,897)	384,913	22,602
Pre-merger Pacific	403GP	SG	23,762	25,347	1,585	20,642	(4,705)
Pre-merger Utah	403GP	SG	73,045	69,461	(3,584)	77,137	7,676
Post-merger	403GP	SG	9,665,735	10,445,515	779,781	10,199,341	(246,175)
General Office	403GP	SO	15,567,254	16,922,698	1,355,444	17,861,183	938,485
General Office	403GP	SG	144,337	137,286	(7,051)	137,286	-
General Office	403GP	SG	8,187	8,879	692	8,879	-
Customer Service	403GP	CN	1,040,345	775,894	(264,451)	846,011	70,117
Fuel Related	403GP	SE	95,328	104,976	9,648	117,402	12,426
Total General Plant			41,391,464	45,195,068	3,803,604	46,657,902	1,462,833
Total Depreciation Expense			716,091,544	846,913,007	**130,821,463**	1,083,601,160	**236,688,153**
					Ref 6.1		**Ref 6.1.2**

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation and Amortization Expense Summary

Description	Account	Factor	12 ME Jun 2019 Expense	Annualized Existing Rates Dec 2020 Expense	Adjustment to Test Period	Proposed Rates Dec 2020 Expense	Adjustment to Proposed Depreciation Rates
AMORTIZATION EXPENSE							
Intangible Plant:							
California	404IP	CA	1,765	4,102	2,337	4,102	-
Customer Service	404IP	CN	9,726,915	10,650,150	923,235	10,650,150	-
Pre-merger Utah	404IP	SG	16,485	16,485	(0)	16,485	-
Pre-merger Pacific	404IP	SG	78,646	-	(78,646)	-	-
Idaho	404IP	ID	23,042	23,033	(8)	23,033	-
Oregon	404IP	OR	10,341	13,738	3,397	13,738	-
Fuel Related	404IP	SE	1,239	-	(1,239)	-	-
Post-merger	404IP	SG	14,326,925	7,564,896	(6,762,029)	7,564,896	-
Hydro Relicensing	404IP	SG-P	10,915,568	2,616,793	(8,298,775)	2,616,793	-
Hydro Relicensing	404IP	SG-U	315,841	314,803	(1,038)	314,803	-
Post-merger	404IP	SG	21,649	-	(21,649)	-	-
General Office	404IP	SO	10,992,229	16,442,185	5,449,956	16,442,185	-
Utah	404IP	UT	(3,576,248)	(3,416,491)	159,758	(3,416,491)	-
Washington	404IP	WA	3,024	3,024	-	3,024	-
Eastern Wyoming	404IP	WYP	107,692	105,757	(1,935)	105,757	-
Western Wyoming	404IP	WYU	-	-	-	-	-
Total Intangible Plant			42,965,111	34,338,476	(8,626,636)	34,338,476	-
Hydro Production Plant:							
Pre-merger Pacific	404HP	SG	-	-	-	-	-
Post-merger	404HP	SG-P	311,125	311,696	571	311,696	-
Post-merger	404HP	SG-U	-	-	-	-	-
Total Hydro Plant			311,125	311,696	571	311,696	-
Other Production Plant:							
Post-merger	404OP	SG	-	-	-	-	-
Total Other Plant			-	-	-	-	-
General Plant:							
California	404GP	CA	67,062	28,016	(39,046)	28,016	-
General Office	404GP	CN	-	-	-	-	-
Oregon	404GP	OR	308,163	249,902	(58,262)	249,902	-
General Office	404GP	SO	289,934	284,353	(5,581)	284,353	-
Utah	404GP	UT	728	728	(0)	728	-
Washington	404GP	WA	82,034	80,507	(1,526)	80,507	-
Eastern Wyoming	404GP	WYP	118,538	48,119	(70,419)	48,119	-
Western Wyoming	404GP	WYU	-	-	-	-	-
Total General Plant			866,459	691,624	(174,834)	691,624	-
Total Amortization			44,142,695	35,341,796	**(8,800,899)**	35,341,796	**-**
					Ref 6.1.1		**Ref 6.1.2**
Total Depreciation and Amortization			760,234,239	882,254,803	122,020,564	1,118,942,956	236,688,153
				Ref. 6.1.16		**Ref. 6.1.16**	

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PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Jun 2019	Depreciation Expense Jun 2019	Adjustments	Adjusted EPIS Balance Jul 2019	Depreciation Expense Jul 2019	Adjustments	Adjusted EPIS Balance Aug 2019	Depreciation Expense Aug 2019	Adjustments	Adjusted EPIS Balance Sep 2019	Depreciation Expense Sep 2019	Adjustments	Adjusted EPIS Balance Oct 2019	Depreciation Expense Oct 2019
DEPRECIATION EXPENSE																	
Steam Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Geothermal - Blundell	SG																
Pollution Control Equipment	SG																
Pollution Control Equipment	SG																
Post-merger - Cholla	SG																
Total Steam Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG-P																
Post-merger	SG-U																
Klamath	SG-P																
Total Hydro Plant																	
Other Production Plant:																	
Pre-merger Utah	SG	[redacted]															
Post-merger	SG																
Post-merger Wind	SG-W																
Black Cap Solar	OR																
Post-merger	SG																
Total Other Plant																	
Transmission Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Total Transmission Plant																	
Distribution Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Total Distribution Plant																	
General Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Pre-merger Pacific	SG																
Pre-merger Utah	SG																
Post-merger	SG																
General Office	SO																
General Office	SG																
General Office	SG																
Customer Service	CN																
Fuel Related	SE																
Total General Plant																	
Mining Plant:																	
Coal Mine	SE	[redacted]															
Total Mining Plant																	
Total Depreciation Expense				[redacted]													

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PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Jun 2019	Depreciation Expense Jun 2019	Adjustments	Adjusted EPIS Balance Jul 2019	Depreciation Expense Jul 2019	Adjustments	Adjusted EPIS Balance Aug 2019	Depreciation Expense Aug 2019	Adjustments	Adjusted EPIS Balance Sep 2019	Depreciation Expense Sep 2019	Adjustments	Adjusted EPIS Balance Oct 2019	Depreciation Expense Oct 2019
AMORTIZATION EXPENSE																	
Intangible Plant:																	
California	CA	[redacted]															
Customer Service	CN																
Pre-merger Utah	SG																
Pre-merger Pacific	SG																
Idaho	ID																
Oregon	OR																
Fuel Related	SE																
Post-merger	SG																
Hydro Relicensing	SG-P																
Hydro Relicensing	SG-U																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Klamath	SG-P																
Total Intangible Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Post-merger	SG-P																
Post-merger	SG-U																
Total Hydro Plant																	
Other Production Plant:																	
Post-merger	SG	[redacted]															
Total Other Plant																	
General Plant:																	
California	CA	[redacted]															
General Office	CN																
Oregon	OR																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Total General Plant																	
Total Amortization				[redacted]													
Total Depreciation & Amortization				[redacted]													

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

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Description	Factor	Existing Rate	Proposed Rate	Adjustments	Adjusted EPIS Balance Nov 2019	Depreciation Expense Nov 2019	Adjustments	Adjusted EPIS Balance Dec 2019	Depreciation Expense Dec 2019	Adjustments	Adjusted EPIS Balance Jan 2020	Depreciation Expense Jan 2020	Adjustments	Adjusted EPIS Balance Feb 2020	Depreciation Expense Feb 2020	Adjustments	Adjusted EPIS Balance Mar 2020
DEPRECIATION EXPENSE																	
Steam Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Geothermal - Blundell	SG																
Pollution Control Equipment	SG																
Pollution Control Equipment	SG																
Post-merger - Cholla	SG																
Total Steam Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG-P																
Post-merger	SG-U																
Klamath	SG-P																
Total Hydro Plant																	
Other Production Plant:																	
Pre-merger Utah	SG	[redacted]															
Post-merger	SG																
Post-merger Wind	SG-W																
Black Cap Solar	OR																
Post-merger	SG																
Total Other Plant																	
Transmission Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Total Transmission Plant																	
Distribution Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Total Distribution Plant																	
General Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Pre-merger Pacific	SG																
Pre-merger Utah	SG																
Post-merger	SG																
General Office	SO																
General Office	SG																
General Office	SG																
Customer Service	CN																
Fuel Related	SE																
Total General Plant																	
Mining Plant:																	
Coal Mine	SE	[redacted]															
Total Mining Plant																	
Total Depreciation Expense				[redacted]													

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Existing Rate	Proposed Rate	Adjustments	Adjusted EPIS Balance Nov 2019	Depreciation Expense Nov 2019	Adjustments	Adjusted EPIS Balance Dec 2019	Depreciation Expense Dec 2019	Adjustments	Adjusted EPIS Balance Jan 2020	Depreciation Expense Jan 2020	Adjustments	Adjusted EPIS Balance Feb 2020	Depreciation Expense Feb 2020	Adjustments	Adjusted EPIS Balance Mar 2020
AMORTIZATION EXPENSE																	
Intangible Plant:																	
California	CA	[redacted]															
Customer Service	CN																
Pre-merger Utah	SG																
Pre-merger Pacific	SG																
Idaho	ID																
Oregon	OR																
Fuel Related	SE																
Post-merger	SG																
Hydro Relicensing	SG-P																
Hydro Relicensing	SG-U																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Klamath	SG-P																
Total Intangible Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Post-merger	SG-P																
Post-merger	SG-U																
Total Hydro Plant																	
Other Production Plant:																	
Post-merger	SG	[redacted]															
Total Other Plant																	
General Plant:																	
California	CA	[redacted]															
General Office	CN																
Oregon	OR																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Total General Plant																	
Total Amortization				[redacted]													
Total Depreciation & Amortization				[redacted]													

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PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Existing Rate	Proposed Rate	Depreciation Expense Mar 2020	Adjustments	Adjusted EPIS Balance Apr 2020	Depreciation Expense Apr 2020	Adjustments	Adjusted EPIS Balance May 2020	Depreciation Expense May 2020	Adjustments	Adjusted EPIS Balance Jun 2020	Depreciation Expense Jun 2020	Adjustments	Adjusted EPIS Balance Jul 2020	Depreciation Expense Jul 2020	Adjustments
DEPRECIATION EXPENSE																	
Steam Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Geothermal - Blundell	SG																
Pollution Control Equipment	SG																
Pollution Control Equipment	SG																
Post-merger - Cholla	SG																
Total Steam Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG-P																
Post-merger	SG-U																
Klamath	SG-P																
Total Hydro Plant																	
Other Production Plant:																	
Pre-merger Utah	SG	[redacted]															
Post-merger	SG																
Post-merger Wind	SG-W																
Black Cap Solar	OR																
Post-merger	SG																
Total Other Plant																	
Transmission Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Total Transmission Plant																	
Distribution Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Total Distribution Plant																	
General Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Pre-merger Pacific	SG																
Pre-merger Utah	SG																
Post-merger	SG																
General Office	SO																
General Office	SG																
General Office	SG																
Customer Service	CN																
Fuel Related	SE																
Total General Plant																	
Mining Plant:																	
Coal Mine	SE	[redacted]															
Total Mining Plant																	
Total Depreciation Expense				[redacted]													

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

REDACTED

Description	Factor	Existing Rate	Proposed Rate	Depreciation Expense Mar 2020	Adjustments	Adjusted EPIS Balance Apr 2020	Depreciation Expense Apr 2020	Adjustments	Adjusted EPIS Balance May 2020	Depreciation Expense May 2020	Adjustments	Adjusted EPIS Balance Jun 2020	Depreciation Expense Jun 2020	Adjustments	Adjusted EPIS Balance Jul 2020	Depreciation Expense Jul 2020	Adjustments
AMORTIZATION EXPENSE																	
Intangible Plant:																	
California	CA	[redacted]															
Customer Service	CN																
Pre-merger Utah	SG																
Pre-merger Pacific	SG																
Idaho	ID																
Oregon	OR																
Fuel Related	SE																
Post-merger	SG																
Hydro Relicensing	SG-P																
Hydro Relicensing	SG-U																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Klamath	SG-P																
Total Intangible Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Post-merger	SG-P																
Post-merger	SG-U																
Total Hydro Plant																	
Other Production Plant:																	
Post-merger	SG	[redacted]															
Total Other Plant																	
General Plant:																	
California	CA	[redacted]															
General Office	CN																
Oregon	OR																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Total General Plant																	
Total Amortization				[redacted]													
Total Depreciation & Amortization				[redacted]													

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Aug 2020	Depreciation Expense Aug 2020	Adjustments	Adjusted EPIS Balance Sep 2020	Depreciation Expense Sep 2020	Adjustments	Adjusted EPIS Balance Oct 2020	Depreciation Expense Oct 2020	Adjustments	Adjusted EPIS Balance Nov 2020	Depreciation Expense Nov 2020	Adjustments	Adjusted EPIS Balance Dec 2020	Depreciation Expense Dec 2020
DEPRECIATION EXPENSE																	
Steam Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Geothermal - Blundell	SG																
Pollution Control Equipment	SG																
Pollution Control Equipment	SG																
Post-merger - Cholla	SG																
Total Steam Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG-P																
Post-merger	SG-U																
Klamath	SG-P																
Total Hydro Plant																	
Other Production Plant:																	
Pre-merger Utah	SG	[redacted]															
Post-merger	SG																
Post-merger Wind	SG-W																
Black Cap Solar	OR																
Post-merger	SG																
Total Other Plant																	
Transmission Plant:																	
Pre-merger Pacific	SG	[redacted]															
Pre-merger Utah	SG																
Post-merger	SG																
Total Transmission Plant																	
Distribution Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Total Distribution Plant																	
General Plant:																	
California	CA	[redacted]															
Oregon	OR																
Washington	WA																
Eastern Wyoming	WYP																
Utah	UT																
Idaho	ID																
Western Wyoming	WYU																
Pre-merger Pacific	SG																
Pre-merger Utah	SG																
Post-merger	SG																
General Office	SO																
General Office	SG																
General Office	SG																
Customer Service	CN																
Fuel Related	SE																
Total General Plant																	
Mining Plant:																	
Coal Mine	SE	[redacted]															
Total Mining Plant																	
Total Depreciation Expense				[redacted]													

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

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Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Aug 2020	Depreciation Expense Aug 2020	Adjustments	Adjusted EPIS Balance Sep 2020	Depreciation Expense Sep 2020	Adjustments	Adjusted EPIS Balance Oct 2020	Depreciation Expense Oct 2020	Adjustments	Adjusted EPIS Balance Nov 2020	Depreciation Expense Nov 2020	Adjustments	Adjusted EPIS Balance Dec 2020	Depreciation Expense Dec 2020
AMORTIZATION EXPENSE																	
Intangible Plant:																	
California	CA	[redacted]															
Customer Service	CN																
Pre-merger Utah	SG																
Pre-merger Pacific	SG																
Idaho	ID																
Oregon	OR																
Fuel Related	SE																
Post-merger	SG																
Hydro Relicensing	SG-P																
Hydro Relicensing	SG-U																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Klamath	SG-P																
Total Intangible Plant																	
Hydro Production Plant:																	
Pre-merger Pacific	SG	[redacted]															
Post-merger	SG-P																
Post-merger	SG-U																
Total Hydro Plant																	
Other Production Plant:																	
Post-merger	SG	[redacted]															
Total Other Plant																	
General Plant:																	
California	CA	[redacted]															
General Office	CN																
Oregon	OR																
General Office	SO																
Utah	UT																
Washington	WA																
Eastern Wyoming	WYP																
Western Wyoming	WYU																
Total General Plant																	
Total Amortization				[redacted]													
Total Depreciation & Amortization				[redacted]													

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Existing Rate	Proposed Rate	Annualized Existing Rates Depreciation Expense	Proposed Rate Depreciation Expense
DEPRECIATION EXPENSE					
Steam Production Plant:					
Pre-merger Pacific	SG	[redacted]			
Pre-merger Utah	SG				
Post-merger	SG				
Geothermal - Blundell	SG				
Pollution Control Equipment	SG				
Pollution Control Equipment	SG				
Post-merger - Cholla	SG				
Total Steam Plant					
Hydro Production Plant:					
Pre-merger Pacific	SG	[redacted]			
Pre-merger Utah	SG				
Post-merger	SG-P				
Post-merger	SG-U				
Klamath	SG-P				
Total Hydro Plant					
Other Production Plant:					
Pre-merger Utah	SG	[redacted]			
Post-merger	SG				
Post-merger Wind	SG-W				
Black Cap Solar	OR				
Post-merger	SG				
Total Other Plant					
Transmission Plant:					
Pre-merger Pacific	SG	[redacted]			
Pre-merger Utah	SG				
Post-merger	SG				
Total Transmission Plant					
Distribution Plant:					
California	CA	[redacted]			
Oregon	OR				
Washington	WA				
Eastern Wyoming	WYP				
Utah	UT				
Idaho	ID				
Western Wyoming	WYU				
Total Distribution Plant					
General Plant:					
California	CA	[redacted]			
Oregon	OR				
Washington	WA				
Eastern Wyoming	WYP				
Utah	UT				
Idaho	ID				
Western Wyoming	WYU				
Pre-merger Pacific	SG				
Pre-merger Utah	SG				
Post-merger	SG				
General Office	SO				
General Office	SG				
General Office	SG				
Customer Service	CN				
Fuel Related	SE				
Total General Plant					
Mining Plant:					
Coal Mine	SE	[redacted]			
Total Mining Plant					
Total Depreciation Expense				[redacted]	

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PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - Dec 2020 Depreciation & Amortization Expense

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Existing Rate	Proposed Rate	Annualized Existing Rates Depreciation Expense	Proposed Rate Depreciation Expense
AMORTIZATION EXPENSE					
Intangible Plant:					
California	CA	[redacted]			
Customer Service	CN				
Pre-merger Utah	SG				
Pre-merger Pacific	SG				
Idaho	ID				
Oregon	OR				
Fuel Related	SE				
Post-merger	SG				
Hydro Relicensing	SG-P				
Hydro Relicensing	SG-U				
General Office	SO				
Utah	UT				
Washington	WA				
Eastern Wyoming	WYP				
Western Wyoming	WYU				
Klamath	SG-P				
Total Intangible Plant					
Hydro Production Plant:					
Pre-merger Pacific	SG	[redacted]			
Post-merger	SG-P				
Post-merger	SG-U				
Total Hydro Plant					
Other Production Plant:					
Post-merger	SG	[redacted]			
Total Other Plant					
General Plant:					
California	CA	[redacted]			
General Office	CN				
Oregon	OR				
General Office	SO				
Utah	UT				
Washington	WA				
Eastern Wyoming	WYP				
Western Wyoming	WYU				
Total General Plant					
Total Amortization			[redacted]	[redacted]	[redacted]
Total Depreciation & Amortization			[redacted]	[redacted]	[redacted]
				Ref. 6.1.6	**Ref. 6.1.6**
				[redacted]	[redacted]

PacifiCorp
Oregon General Rate Case - December 2021
Vehicle Depreciation Expense - Adjustment to Proposed Depreciation Rates

Factor	Vehicle Balance	Year Ending June 2019 Depreciation Existing Rates	Annual Depreciation Study Rates		Difference[1]	
CA	6,490,286	341,236	419,920		78,684	
DGP	332,616	17,488	21,520		4,032	
DGU	1,512,598	79,527	97,865		18,338	
OR	65,421,209	3,439,613	4,232,740		793,128	
SE	724,778	38,106	46,893		8,787	
SG	65,023,909	3,418,724	4,207,035		788,311	
SO	12,987,017	682,811	840,258		157,447	
SSGCH	1,677,855	88,216	108,557		20,341	
SSGCT	44,655	2,348	2,889		541	
UT	87,802,654	4,616,349	5,680,815		1,064,467	
WA	14,265,617	750,035	922,983		172,948	
WYP	27,933,718	1,468,655	1,807,306		338,652	
WYU	5,687,450	299,026	367,977		68,951	
ID	17,176,761	903,092	1,111,333		208,241	
Total	**307,081,124**	**16,145,224**	**19,868,092**		**3,722,868**	
			Labor Pool Allocation	78.41%	2,919,140	
			Direct Allocation	21.59%	**803,728**	**Ref 6.1.3**
					3,722,868	
			Labor Pool Allocation	78.41%	2,919,140	
			Capital/Non Utility		997,294	
					1,921,846	**Ref 6.1.3**

1) This is the difference between depreciation study rates and the exitsing rates.

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation and Amortization Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Depreciation Reserve	108SP	3	(92,451,309)	SG	26.023%	(24,058,264)	
Steam Depreciation Reserve	108SP	3	(67,638,251)	SG	26.023%	(17,601,253)	
Steam Depreciation Reserve	108SP	3	(1,135,473,971)	SG	26.023%	(295,480,219)	
Steam Depreciation Reserve	108SP	3	(117,630,520)	SG	26.023%	(30,610,558)	
Hydro Depreciation Reserve	108HP	3	29,554,661	SG	26.023%	7,690,901	
Hydro Depreciation Reserve	108HP	3	(1,665,024)	SG	26.023%	(433,283)	
Hydro Depreciation Reserve	108HP	3	(62,181,194)	SG-P	26.023%	(16,181,184)	
Hydro Depreciation Reserve	108HP	3	(8,913,953)	SG-U	26.023%	(2,319,645)	
Other Depreciation Reserve	108OP	3	-	SG	26.023%	-	
Other Depreciation Reserve	108OP	3	(60,242,101)	SG	26.023%	(15,676,581)	
Other Depreciation Reserve	108OP	3	1,128,647,420	SG-W	26.023%	293,703,771	
Other Depreciation Reserve	108OP	3	(4,278)	OR	Situs	(4,278)	
Other Depreciation Reserve	108OP	3	(4,562,008)	SG	26.023%	(1,187,155)	
Transmission Depreciation Reserve	108TP	3	(9,939,243)	SG	26.023%	(2,586,453)	
Transmission Depreciation Reserve	108TP	3	(10,005,766)	SG	26.023%	(2,603,764)	
Transmission Depreciation Reserve	108TP	3	(128,136,568)	SG	26.023%	(33,344,508)	
Distribution Depreciation Reserve	108360	3	(1,814,957)	Situs	Situs	(483,809)	
Distribution Depreciation Reserve	108361	3	(3,477,203)	Situs	Situs	(926,910)	
Distribution Depreciation Reserve	108362	3	(29,195,485)	Situs	Situs	(7,782,573)	
Distribution Depreciation Reserve	108364	3	(35,138,208)	Situs	Situs	(9,366,711)	
Distribution Depreciation Reserve	108365	3	(22,353,605)	Situs	Situs	(5,958,749)	
Distribution Depreciation Reserve	108366	3	(11,086,904)	Situs	Situs	(2,955,410)	
Distribution Depreciation Reserve	108367	3	(25,883,767)	Situs	Situs	(6,899,776)	
Distribution Depreciation Reserve	108368	3	(39,865,672)	Situs	Situs	(10,626,900)	
Distribution Depreciation Reserve	108369	3	(23,872,021)	Situs	Situs	(6,363,509)	
Distribution Depreciation Reserve	108370	3	(6,755,200)	Situs	Situs	(1,800,718)	
Distribution Depreciation Reserve	108371	3	(250,669)	Situs	Situs	(66,820)	
Distribution Depreciation Reserve	108373	3	(1,783,924)	Situs	Situs	(475,537)	
General Depreciation Reserve	108GP	3	(898,602)	CA	Situs	-	
General Depreciation Reserve	108GP	3	(7,287,414)	OR	Situs	(7,287,414)	
General Depreciation Reserve	108GP	3	(1,233,808)	WA	Situs	-	
General Depreciation Reserve	108GP	3	(1,349,773)	WYP	Situs	-	
General Depreciation Reserve	108GP	3	(8,324,354)	UT	Situs	-	
General Depreciation Reserve	108GP	3	(1,882,120)	ID	Situs	-	
General Depreciation Reserve	108GP	3	(515,832)	WYU	Situs	-	
General Depreciation Reserve	108GP	3	177,157	SG	26.023%	46,101	
General Depreciation Reserve	108GP	3	(31,430)	SG	26.023%	(8,179)	
General Depreciation Reserve	108GP	3	(11,487,790)	SG	26.023%	(2,989,425)	
General Depreciation Reserve	108GP	3	(3,749,338)	SO	27.215%	(1,020,394)	
General Depreciation Reserve	108GP	3	(98,010)	SG	26.023%	(25,505)	
General Depreciation Reserve	108GP	3	(16,608)	SG	26.023%	(4,322)	
General Depreciation Reserve	108GP	3	1,465,176	CN	31.217%	457,385	
General Depreciation Reserve	108GP	3	(176,323)	SE	25.101%	(44,260)	
Mining Depreciation Reserve	108MP	3	-	SE	25.101%	-	
Total Depreciation Reserve			(777,528,790)			(205,275,908)	6.2.2

Description of Adjustment:

This adjustment steps forward the depreciation reserve to a December 2020 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2019 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2019 to December 31, 2020. An incremental amount has been added to the December 31, 2020 balance to reflect the depreciation expense due to the proposed depreciation study rates being added in through adjustment 6.1.

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation and Amortization Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Intangible Amortization Reserve	111IP	3	(2,745)	CA	Situs	-	
Intangible Amortization Reserve	111IP	3	(15,390,066)	CN	31.217%	(4,804,326)	
Intangible Amortization Reserve	111IP	3	(33,004)	ID	Situs	-	
Intangible Amortization Reserve	111IP	3	(24,727)	SG	26.023%	(6,435)	
Intangible Amortization Reserve	111IP	3	(8,524)	OR	Situs	(8,524)	
Intangible Amortization Reserve	111IP	3	1,106,269	SE	25.101%	277,690	
Intangible Amortization Reserve	111IP	3	(5,439,908)	SG	26.023%	(1,415,607)	
Intangible Amortization Reserve	111IP	3	(7,481,317)	SG-P	26.023%	(1,946,836)	
Intangible Amortization Reserve	111IP	3	(472,205)	SG-U	26.023%	(122,880)	
Intangible Amortization Reserve	111IP	3	(3,634,198)	SO	27.215%	(989,058)	
Intangible Amortization Reserve	111IP	3	-	SG	26.023%	-	
Intangible Amortization Reserve	111IP	3	5,147,222	UT	Situs	-	
Intangible Amortization Reserve	111IP	3	(4,535)	WA	Situs	-	
Intangible Amortization Reserve	111IP	3	79,128	WYP	Situs	-	
Intangible Amortization Reserve	111IP	3	-	WYU	Situs	-	
Intangible Amortization Reserve	111IP	3	-	SG	26.023%	-	
Hydro Amortization Reserve	111HP	3	-	SG	26.023%	-	
Hydro Amortization Reserve	111HP	3	(467,544)	SG-P	26.023%	(121,667)	
Hydro Amortization Reserve	111HP	3	-	SG-U	26.023%	-	
Other Amortizaton Reserve	111OP	3	-	SG	26.023%	-	
General Amortization Reserve	111GP	3	(42,023)	CA	Situs	-	
General Amortization Reserve	111GP	3	-	CN	31.217%	-	
General Amortization Reserve	111GP	3	-	SG	26.023%	-	
General Amortization Reserve	111GP	3	(374,852)	OR	Situs	(374,852)	
General Amortization Reserve	111GP	3	(426,530)	SO	27.215%	(116,081)	
General Amortization Reserve	111GP	3	(1,092)	UT	Situs	-	
General Amortization Reserve	111GP	3	(120,761)	WA	Situs	-	
General Amortization Reserve	111GP	3	(72,178)	WYP	Situs	-	
General Amortization Reserve	111GP	3	-	WYU	Situs	-	
			(27,663,592)			(9,628,577)	6.2.3

Description of Adjustment:

This adjustment steps forward the depreciation reserve to a December 2020 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2019 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2019 to December 31, 2020. An incremental amount has been added to the December 31, 2020 balance to reflect the depreciation expense due to the proposed depreciation study rates being added in through adjustment 6.1.

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation and Amortization Reserve Summary

Description	Account	Factor	12 ME Jun 2019 Reserve	Test Period Reserve Adjusted 2020	Adjustment to Test Period
DEPRECIATION RESERVE					
Steam Production Plant:					
Pre-merger Pacific	108SP	SG	(759,016,718)	(851,468,027)	(92,451,309)
Pre-merger Utah	108SP	SG	(726,882,090)	(794,520,340)	(67,638,251)
Post-merger	108SP	SG	(1,488,197,425)	(2,623,671,396)	(1,135,473,971)
Post-merger - Cholla	108SP	SG	(246,321,600)	(363,952,120)	(117,630,520)
Total Steam Plant			(3,220,417,832)	(4,633,611,882)	(1,413,194,051)
Hydro Production Plant:					
Pre-merger Pacific	108HP	SG	(175,334,101)	(145,779,440)	29,554,661
Pre-merger Utah	108HP	SG	(30,353,650)	(32,018,674)	(1,665,024)
Post-merger	108HP	SG-P	(189,513,434)	(251,694,628)	(62,181,194)
Post-merger	108HP	SG-U	(51,987,503)	(60,901,456)	(8,913,953)
Total Hydro Plant			(447,188,687)	(490,394,198)	(43,205,511)
Other Production Plant:					
Pre-merger Utah	108OP	SG	-	-	-
Post-merger	108OP	SG	(418,175,116)	(478,417,217)	(60,242,101)
Post-merger - Wind	108OP	SG-W	(681,674,033)	446,973,386	1,128,647,420
Black Cap Solar	108OP	OR	-	(4,278)	(4,278)
Post-merger	108OP	SG	(36,871,542)	(41,433,550)	(4,562,008)
Total Other Plant			(1,136,720,691)	(72,881,659)	1,063,839,032
Transmission Plant:					
Pre-merger Pacific	108TP	SG	(351,699,893)	(361,639,135)	(9,939,243)
Pre-merger Utah	108TP	SG	(418,414,202)	(428,419,968)	(10,005,766)
Post-merger	108TP	SG	(1,043,195,644)	(1,171,332,212)	(128,136,568)
Total Transmission Plant			(1,813,309,739)	(1,961,391,316)	(148,081,577)
Distribution Plant:					
California	108364	CA	(138,842,809)	(147,062,217)	(8,219,408)
Oregon	108364	OR	(1,017,251,759)	(1,070,959,180)	(53,707,421)
Washington	108364	WA	(254,269,518)	(271,158,882)	(16,889,363)
Eastern Wyoming	108364	WYP	(264,618,132)	(284,397,235)	(19,779,103)
Utah	108364	UT	(998,035,522)	(1,085,042,946)	(87,007,425)
Idaho	108364	ID	(149,207,836)	(159,630,533)	(10,422,697)
Western Wyoming	108364	WYU	(58,760,424)	(64,212,621)	(5,452,197)
Total Distribution Plant			(2,880,985,998)	(3,082,463,613)	(201,477,615)
General Plant:					
California	108GP	CA	(7,234,341)	(8,132,943)	(898,602)
Oregon	108GP	OR	(84,544,724)	(91,832,139)	(7,287,414)
Washington	108GP	WA	(24,157,433)	(25,391,240)	(1,233,808)
Eastern Wyoming	108GP	WYP	(23,971,348)	(25,321,121)	(1,349,773)
Utah	108GP	UT	(85,056,354)	(93,380,708)	(8,324,354)
Idaho	108GP	ID	(16,831,634)	(18,713,754)	(1,882,120)
Western Wyoming	108GP	WYU	(5,782,407)	(6,298,239)	(515,832)
Pre-merger Pacific	108GP	SG	(843,233)	(666,076)	177,157
Pre-merger Utah	108GP	SG	(2,907,693)	(2,939,123)	(31,430)
Post-merger	108GP	SG	(113,184,624)	(124,672,414)	(11,487,790)
General Office	108GP	SO	(102,867,839)	(106,617,177)	(3,749,338)
General Office	108GP	SG	(2,712,809)	(2,810,818)	(98,010)
General Office	108GP	SG	(110,482)	(127,090)	(16,608)
Customer Service	108GP	CN	(6,314,416)	(4,849,240)	1,465,176
Fuel Related	108GP	SE	(1,583,569)	(1,759,892)	(176,323)
Total General Plant			(478,102,906)	(513,511,975)	(35,409,068)
Mining Plant:					
Coal Mine	108MP	SE	-	-	-
Total Mining Plant			-	-	-
Total Depreciation Reserve			(9,976,725,853)	(10,754,254,643)	**(777,528,790)**
					Ref 6.2

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation and Amortization Reserve Summary

Description	Account	Factor	12 ME Jun 2019 Reserve	Test Period Reserve Adjusted 2020	Adjustment to Test Period
AMORTIZATION RESERVE					
Intangible Plant:					
California	111IP	CA	(2,672)	(5,417)	(2,745)
Customer Service	111IP	CN	(137,070,357)	(152,460,423)	(15,390,066)
Idaho	111IP	ID	(930,856)	(963,860)	(33,004)
Pre-merger Utah	111IP	SG	(489,827)	(514,554)	(24,727)
Oregon	111IP	OR	(105,941)	(114,464)	(8,524)
Fuel Related	111IP	SE	-	1,106,269	1,106,269
Post-merger	111IP	SG	(91,016,089)	(96,455,997)	(5,439,908)
Hydro Relicensing	111IP	SG-P	(105,420,483)	(112,901,800)	(7,481,317)
Hydro Relicensing	111IP	SG-U	(6,044,246)	(6,516,451)	(472,205)
General Office	111IP	SO	(290,867,606)	(294,501,804)	(3,634,198)
Pre-merger Pacific	111IP	SG	-	-	-
Utah	111IP	UT	30,396,632	35,543,854	5,147,222
Washington	111IP	WA	(4,535)	(9,071)	(4,535)
Eastern Wyoming	111IP	WYP	(153,589)	(74,461)	79,128
Western Wyoming	111IP	WYU	-	-	-
General Office	111IP	SG	(21,945)	(21,945)	-
Total Intangible Plant			(601,731,514)	(627,890,126)	(26,158,612)
Hydro Production Plant:					
Pre-merger Pacific	111HP	SG	-	-	-
Post-merger	111HP	SG-P	(2,515,843)	(2,983,387)	(467,544)
Post-merger	111HP	SG-U	-	-	-
Total Hydro Plant			(2,515,843)	(2,983,387)	(467,544)
Other Production Plant:					
Post-merger	111OP	SG	-	-	-
Total Other Plant			-	-	-
General Plant:					
California	111GP	CA	(505,769)	(547,793)	(42,023)
General Office	111GP	CN	-	-	-
Idaho	111GP	ID	(333,771)	(333,771)	-
Oregon	111GP	OR	(4,176,900)	(4,551,753)	(374,852)
General Office	111GP	SO	(3,442,703)	(3,869,233)	(426,530)
Utah	111GP	UT	(17,944)	(19,035)	(1,092)
Washington	111GP	WA	(1,691,029)	(1,811,790)	(120,761)
Eastern Wyoming	111GP	WYP	(4,351,504)	(4,423,682)	(72,178)
Western Wyoming	111GP	WYU	-	-	-
Total General Plant			(14,519,621)	(15,557,057)	(1,037,436)
Total Amortization Reserve			(618,766,978)	(646,430,570)	**(27,663,592)**
					Ref 6.2.1
Total Depreciation & Amortization Reserve			(10,595,492,832)	(11,400,685,213)	(805,192,381)
				Ref. 6.2.11	

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PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Adjusted Reserve Balance Jun 2019	Adjustments	Adjusted Reserve Balance Jul 2019	Adjustments	Adjusted Reserve Balance Aug 2019	Adjustments	Adjusted Reserve Balance Sep 2019	Adjustments	Adjusted Reserve Balance Oct 2019	Adjustments	Adjusted Reserve Balance Nov 2019	Adjustments	Adjusted Reserve Balance Dec 2019
DEPRECIATION RESERVE														
Steam Production Plant:														
Pre-merger Pacific	SG	[redacted]												
Pre-merger Utah	SG													
Post-merger	SG													
Geothermal - Blundell	SG													
Pollution Control Equipment	SG													
Pollution Control Equipment	SG													
Post-merger - Cholla	SG													
Total Steam Plant														
Hydro Production Plant:														
Pre-merger Pacific	SG	[redacted]												
Pre-merger Utah	SG													
Post-merger	SG-P													
Post-merger	SG-U													
Klamath	SG-P													
Total Hydro Plant														
Other Production Plant:														
Pre-merger Utah	SG	[redacted]												
Post-merger	SG													
Post-merger Wind	SG-W													
Black Cap Solar	OR													
Post-merger	SG													
Total Other Plant														
Transmission Plant:														
Pre-merger Pacific	SG	[redacted]												
Pre-merger Utah	SG													
Post-merger	SG													
Total Transmission Plant														
Distribution Plant:														
California	CA	[redacted]												
Oregon	OR													
Washington	WA													
Eastern Wyoming	WYP													
Utah	UT													
Idaho	ID													
Western Wyoming	WYU													
Total Distribution Plant														
General Plant:														
California	CA	[redacted]												
Oregon	OR													
Washington	WA													
Eastern Wyoming	WYP													
Utah	UT													
Idaho	ID													
Western Wyoming	WYU													
Pre-merger Pacific	SG													
Pre-merger Utah	SG													
Post-merger	SG													
General Office	SO													
General Office	SG													
General Office	SG													
Customer Service	CN													
Fuel Related	SE													
Total General Plant														
Mining Plant:														
Coal Mine	SE	[redacted]												
Total Mining Plant														
Total Depreciation Reserve		[redacted]												

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Adjusted Reserve Balance Jun 2019	Adjustments	Adjusted Reserve Balance Jul 2019	Adjustments	Adjusted Reserve Balance Aug 2019	Adjustments	Adjusted Reserve Balance Sep 2019	Adjustments	Adjusted Reserve Balance Oct 2019	Adjustments	Adjusted Reserve Balance Nov 2019	Adjustments	Adjusted Reserve Balance Dec 2019
AMORTIZATION RESERVE														
Intangible Plant:														
California	CA	[redacted]												
Customer Service	CN													
Idaho	ID													
Pre-merger Utah	SG													
Montana	MT													
Oregon	OR													
Fuel Related	SE													
Post-merger	SG													
Hydro Relicensing	SG-P													
Hydro Relicensing	SG-U													
General Office	SO													
Pre-merger Pacific	SG													
Utah	UT													
Washington	WA													
Eastern Wyoming	WYP													
Western Wyoming	WYU													
General Office	SG													
Klamath	SG-P													
Total Intangible Plant														
Hydro Production Plant:														
Pre-merger Pacific	SG	[redacted]												
Post-merger	SG-P													
Post-merger	SG-U													
Total Hydro Plant														
Other Production Plant:														
Post-merger	SG	[redacted]												
Total Other Plant														
General Plant:														
California	CA	[redacted]												
General Office	CN													
General Office	ID													
Oregon	OR													
General Office	SO													
Utah	UT													
Washington	WA													
Eastern Wyoming	WYP													
Western Wyoming	WYU													
Total General Plant														
Total Amortization Reserve		[redacted]												
Total Depreciation & Amortization Reserve		[redacted]												

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Adjustments	Adjusted Reserve Balance Jan 2020	Adjustments	Adjusted Reserve Balance Feb 2020	Adjustments	Adjusted Reserve Balance Mar 2020	Adjustments	Adjusted Reserve Balance Apr 2020	Adjustments	Adjusted Reserve Balance May 2020	Adjustments	Adjusted Reserve Balance Jun 2020	Adjustments
DEPRECIATION RESERVE														
Steam Production Plant:														
Pre-merger Pacific	SG	[redacted]												
Pre-merger Utah	SG													
Post-merger	SG													
Geothermal - Blundell	SG													
Pollution Control Equipment	SG													
Pollution Control Equipment	SG													
Post-merger - Cholla	SG													
Total Steam Plant														
Hydro Production Plant:														
Pre-merger Pacific	SG	[redacted]												
Pre-merger Utah	SG													
Post-merger	SG-P													
Post-merger	SG-U													
Klamath	SG-P													
Total Hydro Plant														
Other Production Plant:														
Pre-merger Utah	SG	[redacted]												
Post-merger	SG													
Post-merger Wind	SG-W													
Black Cap Solar	OR													
Post-merger	SG													
Total Other Plant														
Transmission Plant:														
Pre-merger Pacific	SG	[redacted]												
Pre-merger Utah	SG													
Post-merger	SG													
Total Transmission Plant														
Distribution Plant:														
California	CA	[redacted]												
Oregon	OR													
Washington	WA													
Eastern Wyoming	WYP													
Utah	UT													
Idaho	ID													
Western Wyoming	WYU													
Total Distribution Plant														
General Plant:														
California	CA	[redacted]												
Oregon	OR													
Washington	WA													
Eastern Wyoming	WYP													
Utah	UT													
Idaho	ID													
Western Wyoming	WYU													
Pre-merger Pacific	SG													
Pre-merger Utah	SG													
Post-merger	SG													
General Office	SO													
General Office	SG													
General Office	SG													
Customer Service	CN													
Fuel Related	SE													
Total General Plant														
Mining Plant:														
Coal Mine	SE	[redacted]												
Total Mining Plant														
Total Depreciation Reserve		[redacted]												

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Adjustments	Adjusted Reserve Balance Jan 2020	Adjustments	Adjusted Reserve Balance Feb 2020	Adjustments	Adjusted Reserve Balance Mar 2020	Adjustments	Adjusted Reserve Balance Apr 2020	Adjustments	Adjusted Reserve Balance May 2020	Adjustments	Adjusted Reserve Balance Jun 2020	Adjustments
AMORTIZATION RESERVE														
Intangible Plant:														
California	CA	[redacted]												
Customer Service	CN													
Idaho	ID													
Pre-merger Utah	SG													
Montana	MT													
Oregon	OR													
Fuel Related	SE													
Post-merger	SG													
Hydro Relicensing	SG-P													
Hydro Relicensing	SG-U													
General Office	SO													
Pre-merger Pacific	SG													
Utah	UT													
Washington	WA													
Eastern Wyoming	WYP													
Western Wyoming	WYU													
General Office	SG													
Klamath	SG-P													
Total Intangible Plant														
Hydro Production Plant:														
Pre-merger Pacific	SG	[redacted]												
Post-merger	SG-P													
Post-merger	SG-U													
Total Hydro Plant														
Other Production Plant:														
Post-merger	SG	[redacted]												
Total Other Plant														
General Plant:														
California	CA	[redacted]												
General Office	CN													
General Office	ID													
Oregon	OR													
General Office	SO													
Utah	UT													
Washington	WA													
Eastern Wyoming	WYP													
Western Wyoming	WYU													
Total General Plant														
Total Amortization Reserve		[redacted]												
Total Depreciation & Amortization Reserve		[redacted]												

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Adjusted Reserve Balance Jul 2020	Adjustments	Adjusted Reserve Balance Aug 2020	Adjustments	Adjusted Reserve Balance Sep 2020	Adjustments	Adjusted Reserve Balance Oct 2020	Adjustments	Adjusted Reserve Balance Nov 2020	Adjustments	Adjusted Reserve Balance Dec 2020	CY 2020 YE Balance
DEPRECIATION RESERVE													
Steam Production Plant:													
Pre-merger Pacific	SG	[redacted]											
Pre-merger Utah	SG												
Post-merger	SG												
Geothermal - Blundell	SG												
Pollution Control Equipment	SG												
Pollution Control Equipment	SG												
Post-merger - Cholla	SG												
Total Steam Plant													
Hydro Production Plant:													
Pre-merger Pacific	SG	[redacted]											
Pre-merger Utah	SG												
Post-merger	SG-P												
Post-merger	SG-U												
Klamath	SG-P												
Total Hydro Plant													
Other Production Plant:													
Pre-merger Utah	SG	[redacted]											
Post-merger	SG												
Post-merger Wind	SG-W												
Black Cap Solar	OR												
Post-merger	SG												
Total Other Plant													
Transmission Plant:													
Pre-merger Pacific	SG	[redacted]											
Pre-merger Utah	SG												
Post-merger	SG												
Total Transmission Plant													
Distribution Plant:													
California	CA	[redacted]											
Oregon	OR												
Washington	WA												
Eastern Wyoming	WYP												
Utah	UT												
Idaho	ID												
Western Wyoming	WYU												
Total Distribution Plant													
General Plant:													
California	CA	[redacted]											
Oregon	OR												
Washington	WA												
Eastern Wyoming	WYP												
Utah	UT												
Idaho	ID												
Western Wyoming	WYU												
Pre-merger Pacific	SG												
Pre-merger Utah	SG												
Post-merger	SG												
General Office	SO												
General Office	SG												
General Office	SG												
Customer Service	CN												
Fuel Related	SE												
Total General Plant													
Mining Plant:													
Coal Mine	SE	[redacted]											
Total Mining Plant													
Total Depreciation Reserve		[redacted]											

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Adjusted Reserve Balance Jul 2020	Adjustments	Adjusted Reserve Balance Aug 2020	Adjustments	Adjusted Reserve Balance Sep 2020	Adjustments	Adjusted Reserve Balance Oct 2020	Adjustments	Adjusted Reserve Balance Nov 2020	Adjustments	Adjusted Reserve Balance Dec 2020	CY 2020 YE Balance
AMORTIZATION RESERVE													
Intangible Plant:													
California	CA	[redacted]											
Customer Service	CN												
Idaho	ID												
Pre-merger Utah	SG												
Montana	MT												
Oregon	OR												
Fuel Related	SE												
Post-merger	SG												
Hydro Relicensing	SG-P												
Hydro Relicensing	SG-U												
General Office	SO												
Pre-merger Pacific	SG												
Utah	UT												
Washington	WA												
Eastern Wyoming	WYP												
Western Wyoming	WYU												
General Office	SG												
Klamath	SG-P												
Total Intangible Plant													
Hydro Production Plant:													
Pre-merger Pacific	SG	[redacted]											
Post-merger	SG-P												
Post-merger	SG-U												
Total Hydro Plant													
Other Production Plant:													
Post-merger	SG	[redacted]											
Total Other Plant													
General Plant:													
California	CA	[redacted]											
General Office	CN												
General Office	ID												
Oregon	OR												
General Office	SO												
Utah	UT												
Washington	WA												
Eastern Wyoming	WYP												
Western Wyoming	WYU												
Total General Plant													
Total Amortization Reserve		[redacted]											
Total Depreciation & Amortization Reserve		[redacted]											

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Incremental Reserve For Proposed Study Rates	CY 2020 Adjusted Reserve Year End Balance
DEPRECIATION RESERVE			
Steam Production Plant:			
Pre-merger Pacific	SG	[redacted]	
Pre-merger Utah	SG		
Post-merger	SG		
Geothermal - Blundell	SG		
Pollution Control Equipment	SG		
Pollution Control Equipment	SG		
Post-merger - Cholla	SG		
Total Steam Plant			
Hydro Production Plant:			
Pre-merger Pacific	SG	[redacted]	
Pre-merger Utah	SG		
Post-merger	SG-P		
Post-merger	SG-U		
Klamath	SG-P		
Total Hydro Plant			
Other Production Plant:			
Pre-merger Utah	SG	[redacted]	
Post-merger	SG		
Post-merger Wind	SG-W		
Black Cap Solar	OR		
Post-merger	SG		
Total Other Plant			
Transmission Plant:			
Pre-merger Pacific	SG	[redacted]	
Pre-merger Utah	SG		
Post-merger	SG		
Total Transmission Plant			
Distribution Plant:			
California	CA	[redacted]	
Oregon	OR		
Washington	WA		
Eastern Wyoming	WYP		
Utah	UT		
Idaho	ID		
Western Wyoming	WYU		
Total Distribution Plant			
General Plant:			
California	CA	[redacted]	
Oregon	OR		
Washington	WA		
Eastern Wyoming	WYP		
Utah	UT		
Idaho	ID		
Western Wyoming	WYU		
Pre-merger Pacific	SG		
Pre-merger Utah	SG		
Post-merger	SG		
General Office	SO		
General Office	SG		
General Office	SG		
Customer Service	CN		
Fuel Related	SE		
Total General Plant			
Mining Plant:			
Coal Mine	SE	[redacted]	
Total Mining Plant			
Total Depreciation Reserve		[redacted]	

PacifiCorp
Oregon General Rate Case - December 2021
Jun 2019 - December 2020 Depreciation & Amortization Reserve

Note: Please see Confidential Exhibit PAC/1307_CONF for redacted information.

Description	Factor	Incremental Reserve For Proposed Study Rates	CY 2020 Adjusted Reserve Year End Balance
AMORTIZATION RESERVE			
Intangible Plant:			
California	CA	[redacted]	[redacted]
Customer Service	CN		
Idaho	ID		
Pre-merger Utah	SG		
Montana	MT		
Oregon	OR		
Fuel Related	SE		
Post-merger	SG		
Hydro Relicensing	SG-P		
Hydro Relicensing	SG-U		
General Office	SO		
Pre-merger Pacific	SG		
Utah	UT		
Washington	WA		
Eastern Wyoming	WYP		
Western Wyoming	WYU		
General Office	SG		
Klamath	SG-P		
Total Intangible Plant			
Hydro Production Plant:			
Pre-merger Pacific	SG	[redacted]	[redacted]
Post-merger	SG-P		
Post-merger	SG-U		
Total Hydro Plant			
Other Production Plant:			
Post-merger	SG	[redacted]	[redacted]
Total Other Plant			
General Plant:			
California	CA	[redacted]	[redacted]
General Office	CN		
General Office	ID		
Oregon	OR		
General Office	SO		
Utah	UT		
Washington	WA		
Eastern Wyoming	WYP		
Western Wyoming	WYU		
Total General Plant			
Total Amortization Reserve		[redacted]	[redacted]
Total Depreciation & Amortization Reserve		[redacted]	[redacted]
			Ref. 6.2.3

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Oregon Coal-Fired Steam Plant Depreciation

Depreciation Reserve Adjustment

	Total Company	Factor
Adjustment to June 2019 Reserve:		
Steam Plant Accumulated Depreciation	(704,628,533)	SG
Steam Plant Accumulated Depreciation	(82,848,146)	SG
	(787,476,679)	

Depreciation Reserve Adjustment By Plant

Plant	Factor	Adjustment to Year Ended Jun 2019
CHOLLA	SG	(82,848,146)
NAUGHTON	SG	(16,604,851)
HUNTINGTON	SG	(68,103,815)
HUNTER	SG	(154,222,805)
CRAIG	SG	(21,807,684)
HAYDEN	SG	(14,298,039)
COLSTRIP	SG	(16,249,610)
DAVE JOHNSTON	SG	(131,873,150)
JIM BRIDGER	SG	(203,015,930)
WYODAK	SG	(78,452,649)
		(787,476,679)

This is the increase in the depreciation reserve June 2019 starting balance in adjustment 6.2. This reflects the increase from January 2008 to June 2019 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 2021
Hydro Decommissioning
Spending, Accruals, and Balances - East Side, West Side, and Total Resources

West Side	Spend	Accruals	Balance
June-18	986	(173,152)	(3,835,701)
July-18	636	(173,152)	(4,008,217)
August-18	360	(173,152)	(4,181,009)
September-18	2,445	(173,152)	(4,351,715)
October-18	1,079	(173,152)	(4,523,788)
November-18	51,519	(173,152)	(4,645,421)
December-18	5,019	(173,152)	(4,813,554)
January-19	3,228	(173,152)	(4,983,478)
February-19	1,616	(173,152)	(5,155,013)
March-19	599	(173,152)	(5,327,566)
April-19	1,371	(173,152)	(5,499,346)
May-19	1,559	(173,152)	(5,670,939)
June-19	100	(173,152)	(5,843,991)

East Side	Spend	Accruals	Balance
June-18	-	25,600	(917,352)
July-18	-	25,600	(891,752)
August-18	-	25,600	(866,152)
September-18	-	25,600	(840,551)
October-18	-	25,600	(814,951)
November-18	-	25,600	(789,351)
December-18	-	25,600	(763,750)
January-19	-	25,600	(738,150)
February-19	-	25,600	(712,550)
March-19	-	25,600	(686,949)
April-19	-	25,600	(661,349)
May-19	-	25,600	(635,749)
June-19	-	25,600	(610,148)

Total Resources	Spend	Accruals	Balance
June-18	986	(147,551)	(4,753,053)
July-18	636	(147,551)	(4,899,969)
August-18	360	(147,551)	(5,047,160)
September-18	2,445	(147,551)	(5,192,267)
October-18	1,079	(147,551)	(5,338,739)
November-18	51,519	(147,551)	(5,434,772)
December-18	5,019	(147,551)	(5,577,304)
January-19	3,228	(147,551)	(5,721,628)
February-19	1,616	(147,551)	(5,867,563)
March-19	599	(147,551)	(6,014,515)
April-19	1,371	(147,551)	(6,160,695)
May-19	1,559	(147,551)	(6,306,688)
June-19	100	(147,551)	(6,454,139)

West Side	Spend	Accruals	Balance
July-19	-	(173,152)	(6,017,143)
August-19	469	(173,152)	(6,189,826)
September-19	500	(173,152)	(6,362,478)
October-19	1,400,451	(173,152)	(5,135,178)
November-19	-	(173,152)	(5,308,330)
December-19	-	(173,152)	(5,481,482)
January-20	-	(173,152)	(5,654,634)
February-20	-	(173,152)	(5,827,785)
March-20	-	(173,152)	(6,000,937)
April-20	-	(173,152)	(6,174,089)
May-20	-	(173,152)	(6,347,241)
June-20	-	(173,152)	(6,520,392)
July-20	-	(173,152)	(6,693,544)
August-20	-	(173,152)	(6,866,696)
September-20	-	(173,152)	(7,039,848)
October-20	-	(173,152)	(7,212,999)
November-20	-	(173,152)	(7,386,151)
December-20	-	(173,152)	(7,559,303)

East Side	Spend	Accruals	Balance
July-19	-	25,600	(584,548)
August-19	-	25,600	(558,948)
September-19	-	25,600	(533,347)
October-19	-	25,600	(507,747)
November-19	-	25,600	(482,147)
December-19	-	25,600	(456,546)
January-20	-	25,600	(430,946)
February-20	-	25,600	(405,346)
March-20	-	25,600	(379,745)
April-20	-	25,600	(354,145)
May-20	-	25,600	(328,545)
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)

Total Resources	Spend	Accruals	Balance
July-19	-	(147,551)	(6,601,691)
August-19	469	(147,551)	(6,748,774)
September-19	500	(147,551)	(6,895,825)
October-19	1,400,451	(147,551)	(5,642,925)
November-19	-	(147,551)	(5,790,477)
December-19	-	(147,551)	(5,938,028)
January-20	-	(147,551)	(6,085,580)
February-20	-	(147,551)	(6,233,131)
March-20	-	(147,551)	(6,380,683)
April-20	-	(147,551)	(6,528,234)
May-20	-	(147,551)	(6,675,785)
June-20	-	(147,551)	(6,823,337)
July-20	-	(147,551)	(6,970,888)
August-20	-	(147,551)	(7,118,440)
September-20	-	(147,551)	(7,265,991)
October-20	-	(147,551)	(7,413,542)
November-20	-	(147,551)	(7,561,094)
December-20	-	(147,551)	(7,708,645)

West Side	Spend	Accruals	Balance
January-21	-	6,069	(7,553,234)
February-21	-	6,069	(7,547,164)
March-21	-	6,069	(7,541,095)
April-21	-	6,069	(7,535,025)
May-21	-	6,069	(7,528,956)
June-21	-	6,069	(7,522,887)
July-21	-	6,069	(7,516,817)
August-21	-	6,069	(7,510,748)
September-21	-	6,069	(7,504,679)
October-21	-	6,069	(7,498,609)
November-21	-	6,069	(7,492,540)
December-21	-	6,069	(7,486,471)

East Side	Spend	Accruals	Balance
January-21	-	(18,236)	(167,578)
February-21	-	(18,236)	(185,814)
March-21	-	(18,236)	(204,050)
April-21	-	(18,236)	(222,286)
May-21	-	(18,236)	(240,522)
June-21	-	(18,236)	(258,758)
July-21	-	(18,236)	(276,994)
August-21	-	(18,236)	(295,230)
September-21	-	(18,236)	(313,465)
October-21	-	(18,236)	(331,701)
November-21	-	(18,236)	(349,937)
December-21	-	(18,236)	(368,173)

Total Resources	Spend	Accruals	Balance
January-21	-	(12,167)	(7,720,812)
February-21	-	(12,167)	(7,732,978)
March-21	-	(12,167)	(7,745,145)
April-21	-	(12,167)	(7,757,311)
May-21	-	(12,167)	(7,769,478)
June-21	-	(12,167)	(7,781,645)
July-21	-	(12,167)	(7,793,811)
August-21	-	(12,167)	(7,805,978)
September-21	-	(12,167)	(7,818,144)
October-21	-	(12,167)	(7,830,311)
November-21	-	(12,167)	(7,842,477)
December-21	-	(12,167)	(7,854,644)

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation Allocation Correction

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense							
Remove system allocated deferral	403SP	1	(496,849)	SG	26.023%	(129,293)	6.3.1
Remove system allocated give-back reversal	403SP	1	(2,248,434)	SG	26.023%	(585,102)	6.3.2
			(2,745,282)			(714,395)	

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. This deferred amount is reflected in historical data on a system-allocated basis. Additionally, the Company reverses the depreciation reserve give-backs in Oregon to bring into compliance with the steam plant depreciation rates agreed to in Docket No. UM-1647.

This adjustment removes the system allocated deferral and the steam plant give-back reversal in Oregon. The give-back amount does not need to be incrementally added back since the current rate case incorporates into rates the new depreciation rates through Adjustments 6.1 (Depreciation & Amortization Expense) and 6.2 (Depreciation & Amortization Reserves).

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation Allocation Correction

Description	FERC	Booked Allocation	Total
Amortize Deferred Depr Exp - Steam - UT	4032000	SG	128,043
Amortize Deferred Depr Exp - Steam - WY	4032000	SG	442,191
Defer Deprec Expense - Steam - ID	4032000	SG	(1,923,779)
ID 187320 Deferred Depr amort	4032000	SG	1,850,394
Grand Total			**496,849**
			Ref. 6.3

PacifiCorp
Oregon General Rate Case - December 2021
Depreciation Allocation Correction

Description	FERC	Booked Allocation	Total
OR - Reverse give-back - Colstrip	4032000	SG	627,203
OR - Reverse give-back - Hunter 1&2 Common	4032000	SG	31,585
OR - Reverse give-back - Hunter Common	4032000	SG	154,233
OR - Reverse give-back - Hunter Unit 1	4032000	SG	470,595
OR - Reverse give-back - Hunter Unit 2	4032000	SG	310,286
OR - Reverse give-back - Hunter Unit 3	4032000	SG	654,533
Grand Total			**2,248,434**
			Ref 6.3

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Other Plant Closure Costs

Note: Please see Confidential Exhibit PAC/1308_CONF for redacted information.

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Annual Closure Costs	407	3	40,889,628	SG	26.023%	10,640,558	6.4.1
Bridger Reclamation Costs	501	3	[redacted]	SE	25.101%	[redacted]	6.4.2
Adjustment to Rate Base							
Accum. Reg Liab. - Closure Costs	254	3	(20,444,814)	SG	26.023%	(5,320,279)	6.4.1
Bridger Reclamation Costs	254	3	[redacted]	SE	25.101%	[redacted]	6.4.2
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	40,889,628	SG	26.023%	10,640,558	6.4.1
Deferred Income Tax Expense	41110	3	(10,053,372)	SG	26.023%	(2,616,152)	6.4.1
Accumulated Def Inc Tax Balance	190	3	5,026,686	SG	26.023%	1,308,076	6.4.1
Schedule M Adjustment	SCHMAT	3	[redacted]	SE	25.101%	[redacted]	6.4.2
Deferred Income Tax Expense	41110	3		SE	25.101%		6.4.2
Accumulated Def Inc Tax Balance	190	3		SE	25.101%		6.4.2

Description of Adjustment:

This adjustment adds into test period results other plant closure costs detailed in the 2018 depreciation study. The Company proposes inclusion of these costs in rates with the accumulation of a credit balance to a regulatory liability account. 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 2021. Please refer to the supplemental testimony of Mr. Steven R. McDougal in Docket No. UM-1968 for additional information about the other plant closure costs.

PacifiCorp
Oregon General Rate Case - December 2021
Other Plant Closure Costs
2018 Depreciation Study

REDACTED

Note: Please see Confidential Exhibit PAC/1308_CONF for redacted information.

Plant	Plant Closure Date	Remaining Life (Years)	Other Closure Costs	Total Company Annual Amount
Hunter	2029	9.0	[redacted]	
Huntington	2029	9.0		
Dave Johnston	2027	7.0		
Jim Bridger	2025	5.0		
Naughton	2029	9.0		
Wyodak	2029	9.0		
Hayden	2023	3.0		
			Total	**40,889,628**
				Ref 6.4

	407 Mthly Accum.	SCHMAT Tax	41110 Def Inc Tax Exp	254 Reg. Liab.	190 ADIT
Dec-20	-			-	-
Jan-21	3,407,469	3,407,469	(837,781)	(3,407,469)	837,781
Feb-21	3,407,469	3,407,469	(837,781)	(6,814,938)	1,675,562
Mar-21	3,407,469	3,407,469	(837,781)	(10,222,407)	2,513,343
Apr-21	3,407,469	3,407,469	(837,781)	(13,629,876)	3,351,124
May-21	3,407,469	3,407,469	(837,781)	(17,037,345)	4,188,905
Jun-21	3,407,469	3,407,469	(837,781)	(20,444,814)	5,026,686
Jul-21	3,407,469	3,407,469	(837,781)	(23,852,283)	5,864,467
Aug-21	3,407,469	3,407,469	(837,781)	(27,259,752)	6,702,248
Sep-21	3,407,469	3,407,469	(837,781)	(30,667,221)	7,540,029
Oct-21	3,407,469	3,407,469	(837,781)	(34,074,690)	8,377,810
Nov-21	3,407,469	3,407,469	(837,781)	(37,482,159)	9,215,591
Dec-21	3,407,469	3,407,469	(837,781)	(40,889,628)	10,053,372
Annual Total	**40,889,628**	**40,889,628**	**(10,053,372)**		
		Ref 6.4	**Ref 6.4**		
			13 Mo. Avg.	**(20,444,814)**	**5,026,686**
				Ref 6.4	**Ref 6.4**

PacifiCorp
Oregon General Rate Case - December 2021
Other Plant Closure Costs
Bridger Final Reclamation Costs

REDACTED

Note: Please see Confidential Exhibit PAC/1308_CONF for redacted information.

Annual Incremental Contribution for Reclamation	[redacted]	**Ref 6.4**
Incremental Depreciation Expense Prior to Reclamation	[redacted]	
Years to 2025	5	
Annual Incremental Depreciation Expense	[redacted]	**Ref 6.4**

	501 Mthly Accum.	SCHMAT Tax	41110 Def Inc Tax Exp	254 Reg. Liab.	190 ADIT
Dec-20	[redacted]				
Jan-21					
Feb-21					
Mar-21					
Apr-21					
May-21					
Jun-21					
Jul-21					
Aug-21					
Sep-21					
Oct-21					
Nov-21					
Dec-21					
Annual Total	[redacted]				
		Ref 6.4	**Ref 6.4**		
			13 Mo. Avg.	[redacted]	
				Ref 6.4	**Ref 6.4**

PacifiCorp
Oregon General Rate Case – December 2021
Tax Adjustment Index

The following adjustments were used to arrive at the normalized levels of tax expenses. The Company's 12 months ended June 2019 accrued tax data provided the basis for known and measurable adjustments to the December 2021 test period.

The tax impacts of the following adjustments are included within the adjustment itself:

- Nodal Pricing Model, page 5.2
- Depreciation & Amortization Expense, pages 6.1.3 and 6.1.4
- Other Plant Closure Costs, page 6.4
- Trapper Mine Rate Base, page 8.2
- Jim Bridger Mine Rate Base, page 8.3
- Regulatory Assets & Liabilities Amortization, page 8.8
- Remove Rolling Hills, page 8.9
- Carbon Plant Closure, page 8.10
- Pension and Other Postretirement Plan Balances Removal, page 8.11
- Deer Creek Mine Closure, page 8.12
- Repowering Capital Additions, page 8.13
- EV 2020 Capital Additions, pages 8.14 and 8.14.1
- Cholla Unit 4 Retirement, page 8.15
- Klamath Facilities Capital Additions, page 8.16

The tax impacts of the following adjustments are included within adjustments 7.4 through 7.5:

- Pro Forma Plant Additions 8.5

Pacificorp
Oregon General Rate Case - December 2021
Tab 7 Adjustment Summary

		Total Adjustments	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
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	8,707,023	8,698,280	-	-	-	8,743	-
25	Income Taxes - Federal	(58,244,494)	(1,743,985)	3,672,861	15,939,768	(78,514,536)	(1,753)	1,175,226
26	Income Taxes - State	(4,829,434)	(394,964)	(35)	3,609,916	(8,588,201)	(397)	266,156
27	Income Taxes - Def Net	8,245,699	-	-	(21,778,417)	26,930,946	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-	-
30								
31	Total Operating Expenses:	(46,121,206)	6,559,330	3,672,826	(2,228,732)	(60,171,791)	6,593	1,441,382
32								
33	Operating Rev For Return:	46,121,206	(6,559,330)	(3,672,826)	2,228,732	60,171,791	(6,593)	(1,441,382)
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	(513,876)	61,999	34,716	184,784	(823,295)	62	13,624
45	Weatherization Loans	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	(513,876)	61,999	34,716	184,784	(823,295)	62	13,624
49		-	-	-	-	-	-	-
50	Rate Base Deductions:	-	-	-	-	-	-	-
51	Accum Prov For Deprec	-	-	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-	-	-
53	Accum Def Income Tax	502,844,924	-	-	345,259,313	83,977,138	-	-
54	Unamortized ITC	63,124	-	-	-	63,124	-	-
55	Customer Adv For Const	-	-	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	(349,960,317)	-	-	-	-	-	-
58			-	-	-	-	-	-
59	Total Rate Base Deductions	152,947,731	-	-	345,259,313	84,040,263	-	-
60								
61	Total Rate Base:	152,433,855	61,999	34,716	345,444,097	83,216,967	62	13,624
62								
63	Return on Rate Base	0.951%	-0.188%	-0.105%	-0.587%	1.392%	0.000%	-0.037%
64								
65	Return on Equity	1.777%	-0.350%	-0.196%	-1.096%	2.601%	0.000%	-0.069%
66								
67	TAX CALCULATION:							
68	Operating Revenue	(8,707,023)	(8,698,280)	-	-	-	(8,743)	-
69	Other Deductions	-	-	-	-	-	-	-
70	Interest (AFUDC)	(5,862,773)	-	-	-	-	-	(5,862,773)
71	Interest	3,378,878	1,374	770	7,657,179	1,844,603	1	302
72	Schedule "M" Additions	(10,550,400)	-	-	(48,210,751)	37,660,351	-	-
73	Schedule "M" Deductions	89,601,661	-	-	(135,381,505)	224,983,165	-	-
74	Income Before Tax	(106,375,188)	(8,699,654)	(770)	79,513,574	(189,167,417)	(8,745)	5,862,471
75								
76	State Income Taxes	(4,829,434)	(394,964)	(35)	3,609,916	(8,588,201)	(397)	266,156
77	Taxable Income	(101,545,755)	(8,304,690)	(735)	75,903,658	(180,579,217)	(8,348)	5,596,315
78								
79	Federal Income Taxes + Other	(58,244,494)	(1,743,985)	3,672,861	15,939,768	(78,514,536)	(1,753)	1,175,226
	APPROXIMATE PRICE CHANGE	(47,181,579)	8,997,828	5,038,236	33,294,128	(73,724,953)	9,044	1,977,231

Pacificorp
Oregon General Rate Case - December 2021
Tab 7 Adjustment Summary

		7.8 Removal of TCJA Deferred Balances
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	1,227,925
26	Income Taxes - State	278,091
27	Income Taxes - Def Net	3,093,170
28	Investment Tax Credit Adj.	-
29	Misc Revenue & Expense	-
30		
31	Total Operating Expenses:	4,599,186
32		
33	Operating Rev For Return:	(4,599,186)
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	14,235
45	Weatherization Loans	-
46	Misc Rate Base	-
47		
48	Total Electric Plant:	14,235
49		-
50	Rate Base Deductions:	-
51	Accum Prov For Deprec	-
52	Accum Prov For Amort	-
53	Accum Def Income Tax	73,608,473
54	Unamortized ITC	-
55	Customer Adv For Const	-
56	Customer Service Deposits	-
57	Misc Rate Base Deductions	(349,960,317)
58		-
59	Total Rate Base Deductions	(276,351,844)
60		
61	Total Rate Base:	(276,337,609)
62		
63	Return on Rate Base	0.475%
64		
65	Return on Equity	0.888%
66		
67	TAX CALCULATION:	
68	Operating Revenue	-
69	Other Deductions	-
70	Interest (AFUDC)	-
71	Interest	(6,125,352)
72	Schedule "M" Additions	-
73	Schedule "M" Deductions	-
74	Income Before Tax	6,125,352
75		
76	State Income Taxes	278,091
77	Taxable Income	5,847,261
78		
79	Federal Income Taxes + Other	1,227,925
	APPROXIMATE PRICE CHANGE	(22,773,094)

PacifiCorp
Oregon General Rate Case - December 2021
Interest True-Up

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Interest	427	3	10,602,639	OR	Situs	10,602,639	Below

Adjustment Detail:	**Total Company**		
Interest June 2019 - Unadjusted	309,427,205	82,377,974	2.15
Interest December 2021 - Normalized	363,363,587	92,980,612	Below
Adjustment:	53,936,382	10,602,639	
Normalized Rate Base	16,392,694,778	4,194,704,290	2.2
Adjusted Rate Base	16,392,694,778	4,194,704,290	2.2
Weighted Cost of Debt	2.217%	2.217%	2.1
Normalized Interest	363,363,587	92,980,612	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 2021
Property Tax Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	408	3	31,960,976	GPS	27.215%	8,698,280	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. For additional information on the Company's property tax estimation procedures and methodologies, please refer to Confidential Exhibit PAC/1303.

PacifiCorp
Oregon General Rate Case - December 2021
Propert Tax Expense
Forecasted Property Tax Expense for December 2021
Property Tax Adjustment Summary

FERC Account	G/L Account	Co. Code	Total	Ref
408.15	579000	1000	149,367,024	
Total Accrued Property Tax - 12 Months End. June 2019			149,367,024	
Property Tax Exp. for the Twelve Months Ending Dec 2021			181,328,000	
Less Accrued Property Tax - 12 Months Ended Jun 2019			(149,367,024)	
Incremental Adjustment to Property Taxes			**31,960,976**	**7.2**

PacifiCorp
Oregon General Rate Case - December 2021
Production Tax Credit

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Adj to Pro Forma PTC	40910	3	14,114,694	SG	26.023%	3,673,015	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 is made to reflect the level of wind generation as forecasted by the GRID model for the test period.

As described in the testimony of Ms. Shelley E. McCoy, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; the Company is not requesting recovery of NPC and PTCs as part of the general rate case. NPC and PTCs are reflected in the Company's Transition Adjustment Mechanism filings annually.

PacifiCorp
Oregon General Rate Case - December 2021
Production Tax Credit

Pro Forma Period - December 2021					
Description	**Total Available KWh**	**Repowering Date**	**Total PTC Eligible KWh**	**Factor (inflated tax per unit)**	**Federal Income Tax Credit**
Wind/Geothermal					
Glenrock KWh **[a]**	371,298,054	**9/24/2019**	340,480,316	0.025	8,512,008
Glenrock III KWh **[a]**	137,332,682	**11/24/2019**	113,986,126	0.025	2,849,653
Goodnoe KWh	284,284,154	**12/20/2019**	284,284,154	0.025	7,107,104
High Plains Wind	381,846,971	**12/19/2019**	381,846,971	0.025	9,546,174
Leaning Juniper 1 KWh	299,947,028	**9/13/2019**	299,947,028	0.025	7,498,676
Marengo KWh	488,049,026	1/12/2020	488,049,026	0.025	12,201,226
Marengo II KWh	232,358,922	1/31/2020	232,358,922	0.025	5,808,973
McFadden Ridge	116,449,290	**11/17/2019**	116,449,290	0.025	2,911,232
Rolling Hills KWh **[b]**	-	**10/17/2019**	-	0.025	-
Seven Mile KWh	417,966,868	**9/9/2019**	417,966,868	0.025	10,449,172
Seven Mile II KWh	87,580,562	**9/9/2019**	87,580,562	0.025	2,189,514
Dunlap I Wind KWh	476,696,133	10/15/2020	476,696,133	0.025	11,917,403
Foote Creek I Wind	176,150,151	12/1/2020	176,150,151	0.025	4,403,754
Pryor Mountain Wind	811,935,704	12/31/2020	811,935,704	0.025	20,298,393
Cedar Springs Wind II	749,501,075	11/1/2020	749,501,075	0.025	18,737,527
Ekola Flats Wind	819,429,663	11/1/2020	819,429,663	0.025	20,485,742
TB Flats Wind	847,123,795	11/1/2020	847,123,795	0.025	21,178,095
TB Flats Wind II	847,123,795	11/1/2020	847,123,795	0.025	21,178,095
Total KWh Production	7,545,073,872		7,490,909,577		187,272,741
Federal Renewable Energy Tax Credit					187,272,741

Repowering In Service dates in **bold** reflect actual in-service dates.

[a] Total available Kwh is reflected net of the generation that is not considered PTC eligible because the facility was not fully repowered. For Glenrock, 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 in 2021.

Revised PTCs per OR GRC	(187,272,741)	
Forecast PTCs per Tax Model	(201,387,435)	
Adjustment Needed	**14,114,694**	**Ref 7.3**

PacifiCorp
Oregon General Rate Case - December 2021
PowerTax ADIT Balance

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
California	282	1	28,128,928	CA	Situs	-	
Idaho	282	1	84,223,812	ID	Situs	-	
Oregon	282	1	345,259,313	OR	Situs	345,259,313	
Other	282	1	9,767,176	OTHER	0.000%	-	
Utah	282	1	630,642,618	UT	Situs	-	
Washington	282	1	81,929,211	WA	Situs	-	
Wyoming	282	1	195,704,899	WYP	Situs	-	
			1,375,655,958			345,259,313	7.4.1
Schedule M Adjustment	SCHMAT	3	(219,384,355)	SCHMDEXP	26.726%	(58,632,312)	7.4.1
Schedule M Adjustment	SCHMAT	3	1,157,113	SO	27.215%	314,912	7.4.1
Schedule M Adjustment	SCHMAT	3	12,457,371	CIAC	26.756%	3,333,142	7.4.1
Schedule M Adjustment	SCHMAT	3	25,762,565	SNP	26.292%	6,773,507	7.4.1
Schedule M Adjustment	SCHMDT	3	(542,029,385)	TAXDEPR	26.274%	(142,410,583)	7.4.1
Schedule M Adjustment	SCHMDT	3	(2,451,204)	SG	26.023%	(637,868)	7.4.1
Schedule M Adjustment	SCHMDT	3	30,764,682	SNP	26.292%	8,088,667	7.4.1
Schedule M Adjustment	SCHMDT	3	(1,977,270)	GPS	27.215%	(538,120)	7.4.1
Deferred Income Tax Expense	41110	3	53,939,154	SCHMDEXP	26.726%	14,415,692	7.4.1
Deferred Income Tax Expense	41110	3	(284,495)	SO	27.215%	(77,426)	7.4.1
Deferred Income Tax Expense	41110	3	(3,062,844)	CIAC	26.756%	(819,506)	7.4.1
Deferred Income Tax Expense	41110	3	(6,334,139)	SNP	26.292%	(1,665,375)	7.4.1
Deferred Income Tax Expense	41010	3	(133,266,597)	TAXDEPR	26.274%	(35,013,920)	7.4.1
Deferred Income Tax Expense	41010	3	(602,668)	SG	26.023%	(156,830)	7.4.1
Deferred Income Tax Expense	41010	3	7,563,989	SNP	26.292%	1,988,728	7.4.1
Deferred Income Tax Expense	41010	3	(486,144)	GPS	27.215%	(132,306)	7.4.1
DIT Expense - Flowthrough	41110	3	(346,092)	OR	Situs	(346,092)	7.4.1
Schedule M Adjustment	SCHMDT	1	427,698	SO	27.215%	116,399	
Deferred Income Tax Expense	41010	1	105,156	SO	27.215%	28,619	

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, 2020. Updates the related tax depreciation and book depreciation schedule m items and associated deferred income tax expense for the 12 months ended December 31, 2020. This adjustment also corrects the allocation of the tax schedule m addition and related deferred income tax expense for post-employment costs to correspond with the ADIT treatment.

PacifiCorp
Oregon General Rate Case - December 2021
PowerTax Adjustment for Year Ended December 2020

Book Tax Difference		Total Company			STATE
Description - ADIT	**#**	**Forecast 2021 - Utility**	**Adjustment**	**Adjusted Utility**	**Allocation**
Accumulated Deferred Income Taxes (CA) - YE	**	(91,111,232)	28,128,928	(62,982,304)	CA
Accumulated Deferred Income Taxes (IDU) - YE	**	(249,356,594)	84,223,812	(165,132,782)	ID
Accumulated Deferred Income Taxes (OR) - YE	**	(1,043,312,113)	345,259,313	(698,052,800)	OR
Accumulated Deferred Income Taxes (OTHER) - YE	**	(16,488,625)	9,767,176	(6,721,449)	OTHER
Accumulated Deferred Income Taxes (UT) - YE	**	(1,885,109,252)	630,642,618	(1,254,466,634)	UT
Accumulated Deferred Income Taxes (WA) - YE	**	(265,312,532)	81,929,211	(183,383,321)	WA
Accumulated Deferred Income Taxes (WY) - YE	**	(610,459,311)	195,704,899	(414,754,412)	WYP
Rounding	**	(6)	6	0	DITBAL
		(4,161,149,666)	**1,375,655,964**	**(2,785,493,702)**	
			Ref. 7.4		

Book Tax Difference		Total Company			STATE	
Description - Schedule M Items	**#**	**Forecast 2021 - Utility**	**Adjusted Utility**	**Adjustment**	**Allocation**	
Schedule M Additions:						
Book Depreciation	105.120 & Other	1,141,472,098	922,087,743	(219,384,355)	SCHMDEXP	**Ref 7.4**
Capitalized Labor & Benefits Costs	105.100	4,101,623	5,258,736	1,157,113	SO	**Ref 7.4**
CIAC	105.130	61,508,140	73,965,511	12,457,371	CIAC	**Ref 7.4**
Avoided Costs	Basis Adj 105.142	33,913,243	59,675,808	25,762,565	SNP	**Ref 7.4**
Total Schedule M Adds		1,240,995,104	1,060,987,798	(180,007,306)		
Schedule M Deductions:						
Repair Deduction	105.122	142,519,978	140,068,774	(2,451,204)	SG	**Ref 7.4**
Tax Depreciation	105.125	1,512,377,001	970,347,616	(542,029,385)	TAXDEPR	**Ref 7.4**
AFUDC - Debt	105.141 - Debt	45,834,876	29,495,820	(16,339,056)	SNP	**Ref 7.4**
AFUDC - Equity	105.141 - Equity	24,656,172	71,759,910	47,103,738	SNP	**Ref 7.4**
Tax Gain / (Loss) on Prop. Disposition	105.152	7,870,023	5,892,753	(1,977,270)	GPS	**Ref 7.4**
Total Schedule M Deducts		1,733,258,050	1,217,564,874	(515,693,176)		

Book Tax Difference		Total Company				STATE	
Description - Deferred Income Tax Expense	**#**	**Forecast 2021 - Utility**	**Adjusted Utility**	**Correction to BW**	**Adjustment**	**Allocation**	
Flow-through:							
California	105.115	(271,279)	(298,080)	-	(26,801)	CA	**Ref 7.4**
Idaho	105.115	957,627	(426,145)	-	(1,383,772)	ID	**Ref 7.4**
Oregon	105.115	(2,212,737)	(2,612,939)	54,110	(346,092)	OR	**Ref 7.4**
Washington	105.115	1,090,648	503,922	-	(586,726)	WA	**Ref 7.4**
Wyoming - P	105.115	(723,974)	(1,139,166)	-	(415,192)	WYP	**Ref 7.4**
Wyoming - U	105.115	535,243	(50,636)	-	(585,879)	WYU	**Ref 7.4**
Utah	105.115	6,583,807	(2,049,075)	-	(8,632,882)	UT	**Ref 7.4**
U FERC	105.115	(242,809)	(341,223)	-	(98,414)	FERC	**Ref 7.4**
Other	105.115	(838,872)	(69,834)	-	769,038	OTHER	**Ref 7.4**
Total		4,877,654	(6,483,175)	54,110	(11,306,719)		

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Tax Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Schedule M Adjustment Permanent	SCHMAP	3	13,784	SCHMDEXP	26.726%	3,684	
	SCHMAP	3	(40,125)	SE	25.101%	(10,072)	
	SCHMAP	3	1,346,781	SO	27.215%	366,531	
	SCHMDP	3	544,541	SCHMDEXP	26.726%	145,533	
	SCHMDP	3	3,545,057	SE	25.101%	889,862	
	SCHMDP	3	(106,610)	SNP	26.292%	(28,030)	
Schedule M Adjustment Temporary	SCHMAT	3	(397,328)	BADDEBT	35.662%	(141,695)	
	SCHMAT	3	(3,943,164)	CA	Situs	-	
	SCHMAT	3	(41,493,092)	CIAC	26.756%	(11,102,049)	
	SCHMAT	3	591,042	GPS	27.215%	160,854	
	SCHMAT	3	(138,437)	ID	Situs	-	
	SCHMAT	3	(3,747,653)	OR	Situs	(3,747,653)	
	SCHMAT	3	(52,473,014)	OTHER	0.000%	-	
	SCHMAT	3	157,464,116	SCHMDEXP	26.726%	42,083,608	
	SCHMAT	3	(20,599,304)	SE	25.101%	(5,170,732)	
	SCHMAT	3	89,547,299	SG	26.023%	23,302,565	
	SCHMAT	3	(7,933,430)	SNP	26.292%	(2,085,862)	
	SCHMAT	3	(2,098,862)	SNPD	26.756%	(561,579)	
	SCHMAT	3	(20,027,066)	SO	27.215%	(5,450,429)	
	SCHMAT	3	50,974	TROJD	25.858%	13,181	
	SCHMAT	3	291,300	UT	Situs	-	
	SCHMAT	3	(10,508,304)	WA	Situs	-	
	SCHMAT	3	(714,354)	WYP	Situs	-	
	SCHMDT	3	(917,171)	CA	Situs	-	
	SCHMDT	3	(20,990,264)	GPS	27.215%	(5,712,566)	
	SCHMDT	3	1,450,496	ID	Situs	-	
	SCHMDT	3	11,918,060	OR	Situs	11,918,060	
	SCHMDT	3	(103,998,630)	OTHER	0.000%	-	
	SCHMDT	3	(88,607,033)	SE	25.101%	(22,241,684)	
	SCHMDT	3	(2,872,490)	SG	26.023%	(747,498)	
	SCHMDT	3	(4,214,274)	SNP	26.292%	(1,108,019)	
	SCHMDT	3	(1,526,070)	SNPD	26.756%	(408,321)	
	SCHMDT	3	451,285	SO	27.215%	122,819	
	SCHMDT	3	921,659,360	TAXDEPR	26.274%	242,153,009	
	SCHMDT	3	4,319,027	UT	Situs	-	
	SCHMDT	3	5,900,574	WA	Situs	-	
	SCHMDT	3	557,818	WYP	Situs	-	
Current Tax Credits	40910	3	519	SE	25.101%	130	
	40910	3	(156,034,664)	SG	26.023%	(40,604,327)	
	40910	3	41,507	SO	27.215%	11,296	

Description of Adjustment:

This adjustment normalizes base period schedule M, deferred tax expense, and accumulated deferred income tax balances to an estimated pro forma level for the CY December 2021 test period.

PacifiCorp
Oregon General Rate Case - December 2021
(cont.) Pro Forma Tax Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Deferred Tax Expense Debit	41010	3	(225,501)	CA	Situs	-	
	41010	3	(5,160,793)	GPS	27.215%	(1,404,526)	
	41010	3	356,627	ID	Situs	-	
	41010	3	2,930,246	OR	Situs	2,930,246	
	41010	3	(25,569,725)	OTHER	0.000%	-	
	41010	3	(21,785,458)	SE	25.101%	(5,468,474)	
	41010	3	(706,247)	SG	26.023%	(183,784)	
	41010	3	(1,036,147)	SNP	26.292%	(272,424)	
	41010	3	(375,209)	SNPD	26.756%	(100,392)	
	41010	3	110,955	SO	27.215%	30,197	
	41010	3	226,604,700	TAXDEPR	26.274%	59,537,192	
	41010	3	1,061,902	UT	Situs	-	
	41010	3	1,450,750	WA	Situs	-	
	41010	3	137,148	WYP	Situs	-	
Deferred Tax Expense Credit	41110	3	97,689	BADDEBT	35.662%	34,838	
	41110	3	(2,209,637)	CA	Situs	-	
	41110	3	10,201,741	CIAC	26.756%	2,729,617	
	41110	3	(4,477,298)	ID	Situs	-	
	41110	3	(97,716)	FERC	0.000%	-	
	41110	3	(145,317)	GPS	27.215%	(39,548)	
	41110	3	(18,043,706)	OR	Situs	(18,043,706)	
	41110	3	11,537,883	OTHER	0.000%	-	
	41110	3	(38,715,072)	SCHMDEXP	26.726%	(10,346,928)	
	41110	3	5,064,669	SE	25.101%	1,271,307	
	41110	3	(22,020,897)	SG	26.023%	(5,730,417)	
	41110	3	1,950,560	SNP	26.292%	512,842	
	41110	3	516,039	SNPD	26.756%	138,073	
	41110	3	4,923,975	SO	27.215%	1,340,075	
	41110	3	(12,533)	TROJD	25.858%	(3,241)	
	41110	3	92,475,753	UT	Situs	-	
	41110	3	(10,223,861)	WA	Situs	-	
	41110	3	(18,620,112)	WYP	Situs	-	
ADIT Balance 190	190	3	35,398	BADDEBT	35.662%	12,624	
	190	3	285,963	CA	Situs	-	
	190	3	(280,102)	ID	Situs	-	
	190	3	(5,275,406)	OR	Situs	(5,275,406)	
	190	3	7,078,195	OTHER	0.000%	-	
	190	3	99,152	SE	25.101%	24,889	
	190	3	(25,157,797)	SG	26.023%	(6,546,721)	
	190	3	(26,363,797)	SO	27.215%	(7,174,990)	
	190	3	(9,391)	TROJD	25.858%	(2,428)	
	190	3	10,191,047	UT	Situs	-	
	190	3	2,234,575	WA	Situs	-	
	190	3	1,397,047	WYP	Situs	-	
	190	3	1,137,671	SNPD	26.756%	304,400	
	190	3	(4,334)	FERC	0.000%	-	

Description of Adjustment:

This adjustment normalizes base period schedule M, deferred tax expense, and accumulated deferred income tax balances to an estimated pro forma level for the CY December 2021 test period.

PacifiCorp
Oregon General Rate Case - December 2021
(cont.) Pro Forma Tax Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
ADIT Balance 281	281	3	177,049,368	SG	26.023%	46,072,907	
ADIT Balance 282	282	3	(86,855,620)	CA	Situs	-	
	282	3	3,983,530,289	DITBAL	24.678%	983,075,147	
	282	3	(248,857,579)	ID	Situs	-	
	282	3	(931,868,873)	OR	Situs	(931,868,873)	
	282	3	(16,406,770)	OTHER	0.000%	-	
	282	3	3,353,529	SE	25.101%	841,786	
	282	3	681,745	SG	26.023%	177,408	
	282	3	(31,316)	SO	27.215%	(8,523)	
	282	3	(1,902,231,797)	UT	Situs	-	
	282	3	(260,540,526)	WA	Situs	-	
	282	3	(607,837,612)	WYP	Situs	-	
	282	3	6,799,961	FERC	0.000%	-	
ADIT Balance 283	283	3	(23,362)	CA	Situs	-	
	283	3	(131,204)	GPS	27.215%	(35,708)	
	283	3	233,963	ID	Situs	-	
	283	3	(155,211)	OR	Situs	(155,211)	
	283	3	(49,321,023)	OTHER	0.000%	-	
	283	3	3,439,035	SE	25.101%	863,249	
	283	3	262,275	SG	26.023%	68,251	
	283	3	283,393	SNP	26.292%	74,510	
	283	3	12,970,012	SO	27.215%	3,529,829	
	283	3	249,499	UT	Situs	-	
	283	3	(369,769)	WA	Situs	-	
	283	3	741,113	WYP	Situs	-	
ADIT Balance 255	255	3	42,534	ITC90	15.936%	6,778	
	255	3	216,528	SG	26.023%	56,346	
	255	3	38,436	ID	Situs	-	

Description of Adjustment:

This adjustment normalizes base period schedule M, deferred tax expense, and accumulated deferred income tax balances to an estimated pro forma level for the CY December 2021 test period.

PacifiCorp
Oregon General Rate Case - December 2021
Wyoming Wind Generation Tax

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	408	3	33,599	SG	26.023%	8,743	7.6.1

Description of Adjustment:

This adjustment normalizes into the test year results the Wyoming Wind Generation Tax that became effective January 1, 2012. The Wyoming Wind Generation Tax is an excise tax levied upon the priviledge of producing electricity from wind resources in the state of Wyoming. The tax is on the production of any electricity produced from wind resources for sale or trade on or after January 1, 2012, and is to be paid by the person producing the electricity. New wind facilities are exempt from the tax for three years following the date the facility first produces electricity for sale. The tax is one dollar 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 2021
Wyoming Wind Generation Tax

Wind Plant	2021 MWH Production (b)	Tax Begins	2021 $1/MWH Tax	
Foote Creek, Wyoming (a)	-	12/1/2023	-	
Glenrock I Wind Plant	371,298	1/1/2012	371,298	
Seven Mile Hill Wind Plant	417,967	1/1/2012	417,967	
Seven Mile Hill II Wind Plant	87,581	1/1/2012	87,581	
Glenrock III Wind Plant	137,333	1/1/2012	137,333	
High Plains Wind Plant	381,847	9/1/2012	381,847	
McFadden Ridge	116,449	9/1/2012	116,449	
Dunlap I Wind	476,696	10/1/2013	476,696	
Cedar Springs Wind II, Wyoming (a)	-	12/1/2023	-	
Ekola Flats Wind, Wyoming (a)	-	12/1/2023	-	
TB Flats Wind, Wyoming (a)	-	12/1/2023	-	
TB Flats Wind II, Wyoming (a)	-	12/1/2023	-	
Total WY Wind MWH	1,989,170		1,989,171	
Booked through June 2019			1,955,572	
Adjustment to normalize to CY December 2021			**33,599**	**Ref 7.6.1**

(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.

Pacific Power
Oregon General Rate Case - December 2021
AFUDC - Equity

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
AFUDC - Equity	419	1	(22,298,652)	SNP	26.2921%	(5,862,773)	7.7.1

Description of Adjustment:

This adjustment brings in the appropriate level of AFUDC - Equity into results to align the tax Schedule M with regulatory income.

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Oregon General Rate Case - December 2021
AFUDC - Equity

			Equity SAP Accts 382000 & 382060	
Jun-19	12 months	Account 419	(49,461,258)	
Dec-20	12 months	AFUDC-Equity SCHMDT	(71,759,910)	
Adjustment to Account 419			**(22,298,652)**	**Ref. 7.7**

PacifiCorp
Oregon General Rate Case - December 2021
Removal of TCJA Deferred Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustments to Rate Base:							
Reg Liab - Non-Property EDIT - OR	254	1	15,768,651	OR	Situs	15,768,651	B15
Reg Liab - Excess Income Tax Deferral - OR	254	1	50,091,425	OTHER	0.000%	-	B15
Reg Liab - Protected PP&E EDIT - OR	254	1	(380,438,421)	OR	Situs	(380,438,421)	
Reg Liab - Protected PP&E EDIT Amort - OR	254	1	14,709,453	OR	Situs	14,709,453	B15
Adjustments to Tax:							
DTL 705.289 RL-Protected PP&E EDIT - OR	190	1	93,536,875	OR	Situs	93,536,875	
DTA 705.348 - Protected PP&E EDIT Amortization - OR	190	1	(2,069,852)	OR	Situs	(2,069,852)	
DTL Non-Prot PP&E EDIT - OR	282	1	(18,163,331)	OR	Situs	(18,163,331)	
DTL PMI PP&E - Protected Property EDIT	282	1	1,214,196	SE	25.101%	304,781	
Protected PP&E EDIT Amortization - OR	41110	1	3,093,170	OR	Situs	3,093,170	

Description of Adjustment:

This adjustment reflects the removal of tax deferral balances as a result of the Tax Cuts and Jobs Act that was enacted on December 22, 2017. The tax rate was reduced from 35% to 21% effective January 1, 2018. The related tax deferral balances will be removed from the base period and amortization via a separate tariff or rider will be proposed as part of the GRC.

Current Tax: Pursuant to Docket UM-1985, Order 19-028, the benefit of the new tax rate will be returned using a rolling deferral and amortization process until the the next general rate case. Therefore, the amount deferred in 2018 will be returned over 12 months starting on February 1, 2019 through Schedule 195, and the deferral in 2019 will be returned in 2020. Both the 2018 and 2019 deferrals are to be reduced by $1.5m to offset the 2018 TAM. The return of the deferral for 2020 will need to be decided upon in the current rate case.

Non-protected PP&E EDIT, Non-Property EDIT and Deferred Protected EDIT Amortization: Pursuant to Docket UM-1985, Order No. 19-028, all EDIT will continue to be deferred until the next rate case, with the exception of the balances utilized as part of the 2019 OR RAC Settlement. Pursuant to the Oregon Renewable Adjustment Clause settlement (UE 352, Order 19-034), approximately $159.7m of non-protected EDIT balances will be used to accelerate the depreciation on Oregon's share of certain repowered wind facilities in September 2019, December 2019 and Q1 2020. As of December 2019, $90.5m, or $120.0m including gross up, of non-protected EDIT balances have been amortized pursuant to this settlement. Another $30.9m, or $40.4m including gross up, is expected to be amortized in Q1 2020.

Protected PP&E EDIT: This adjustment also reflects the level of protected property EDIT amortization for the test period and adjusts the rate base to the appropriate levels

PacifiCorp

Oregon General Rate Case – December 2021

Rate Base Adjustment Index

The Company used year-end rate base as of June 2019 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 2021 13 month average balance. The following rate base adjustments are included.

8.1 Cash Working Capital
8.2 Trapper Mine Rate Base
8.3 Bridger Mine Rate Base
8.4 Customer Advances for Construction
8.5 Pro Forma Plant Additions
8.6 Miscellaneous Rate Base
8.7 FERC 105 (PHFU) Adjustment
8.8 Regulatory Assets & Liabilities Amortization
8.9 Remove Rolling Hills
8.10 Carbon Plant Closure
8.11 Pension and Other Postretirement Plan Balances Removal
8.12 Deer Creek Mine Adjustment
8.13 Repowering Projects Capital Addition
8.14 EV 2020 Capital Addition
8.15 Cholla Unit 4 Retirement
8.16 Klamath Facilities Capital Additions

Pacificorp
Oregon General Rate Case - December 2021
Tab 8 Adjustment Summary

			8.2	8.3	8.4	8.5	8.6	8.7
		Total Adjustments	Trapper Mine Rate Base	Jim Bridger Mine Rate Base	Customer Advances for Construction	Pro Forma Plant Additions	Miscellaneous Rate Base	FERC 105 (PHFU) Adjustment
1	Operating Revenues:							
2	General Business Revenues	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-	-
5	Other Operating Revenues	4,630,292	-	-	-	-	-	-
6	Total Operating Revenues	4,630,292	-	-	-	-	-	-
7								
8	Operating Expenses:	-						
9	Steam Production	(6,582,064)	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-
11	Hydro Production	-	-	-	-	-	-	-
12	Other Power Supply	4,042,177	-	-	-	-	-	-
13	Transmission	-	-	-	-	-	-	-
14	Distribution	-	-	-	-	-	-	-
15	Customer Accounting	-	-	-	-	-	-	-
16	Customer Service & Info	-	-	-	-	-	-	-
17	Sales	-	-	-	-	-	-	-
18	Administrative & General	(3,264,165)	-	-	-	-	-	-
19								
20	Total O&M Expenses	(5,804,053)	-	-	-	-	-	-
21			-	-	-	-	-	-
22	Depreciation	24,764,195	-	-	-	-	-	-
23	Amortization	(1,795,238)	-	-	-	-	-	-
24	Taxes Other Than Income	-	-	-	-	-	-	-
25	Income Taxes - Federal	(19,734,923)	5,541	(86,402)	(11,199)	(454,061)	11,175	47,544
26	Income Taxes - State	(4,469,414)	1,255	(19,568)	(2,536)	(102,832)	2,531	10,767
27	Income Taxes - Def Net	18,214,115	(14,535)	-	-	-	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-	-
30								
31	Total Operating Expenses:	11,174,683	(7,739)	(105,970)	(13,736)	(556,893)	13,706	58,311
32								
33	Operating Rev For Return:	(6,544,392)	7,739	105,970	13,736	556,893	(13,706)	(58,311)
34								
35	Rate Base:							
36	Electric Plant In Service	727,352,118	1,515,183	19,290,185	-	102,189,177	-	-
37	Plant Held for Future Use	(10,699,976)	-	-	-	-	-	(10,699,976)
38	Misc Deferred Debits	(118,340,307)	-	-	-	-	873,314	-
39	Elec Plant Acq Adj	(2,488,575)	-	-	-	-	-	-
40	Nuclear Fuel	(676,399)	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-	-
42	Fuel Stock	(3,388,408)	-	-	-	-	(3,388,408)	-
43	Material & Supplies	(1,723,272)	-	-	-	-	-	-
44	Working Capital	(403,824)	(120,121)	(1,002)	(130)	(5,264)	130	551
45	Weatherization Loans	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	589,631,356	1,395,063	19,289,183	(130)	102,183,913	(2,514,964)	(10,699,425)
49			-	-	-	-	-	-
50	Rate Base Deductions:		-	-	-	-	-	-
51	Accum Prov For Deprec	(91,044,646)	-	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-	-	-
53	Accum Def Income Tax	22,205,926	24,998	155,128	-	-	-	-
54	Unamortized ITC	-	-	-	-	-	-	-
55	Customer Adv For Const	2,520,464	-	-	2,520,464	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	18,687,478	-	-	-	-	-	-
58			-	-	-	-	-	-
59	Total Rate Base Deductions	(47,630,778)	24,998	155,128	2,520,464	-	-	-
60								
61	Total Rate Base:	542,000,578	1,420,061	19,444,311	2,520,334	102,183,913	(2,514,964)	(10,699,425)
62								
63	Return on Rate Base	-1.244%	-0.003%	-0.042%	-0.005%	-0.212%	0.005%	0.022%
64								
65	Return on Equity	-2.324%	-0.006%	-0.078%	-0.010%	-0.395%	0.009%	0.040%
66								
67	TAX CALCULATION:							
68	Operating Revenue	(12,534,613)	-	-	-	-	-	-
69	Other Deductions	-	-	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-	-	-
71	Interest	12,014,088	31,477	431,006	55,866	2,265,028	(55,747)	(237,165)
72	Schedule "M" Additions	20,469,088	59,116	-	-	-	-	-
73	Schedule "M" Deductions	94,365,623	-	-	-	-	-	-
74	Income Before Tax	(98,445,236)	27,639	(431,006)	(55,866)	(2,265,028)	55,747	237,165
75								
76	State Income Taxes	(4,469,414)	1,255	(19,568)	(2,536)	(102,832)	2,531	10,767
77	Taxable Income	(93,975,822)	26,384	(411,439)	(53,330)	(2,162,196)	53,216	226,398
78								
79	Federal Income Taxes + Other	(19,734,923)	5,541	(86,402)	(11,199)	(454,061)	11,175	47,544
	APPROXIMATE PRICE CHANGE	66,002,590	138,817	1,900,759	246,373	9,988,885	(245,848)	(1,045,912)

Pacificorp
Oregon General Rate Case - December 2021
Tab 8 Adjustment Summary

	8.8	8.9	8.10	8.11	8.12	8.13	8.14	8.15
	Regulatory Assets & Liabilities Amortization	Remove Rolling Hills	Carbon Plant Closure	Pension and Other Post-retirement Plan Balances Removal	Deer Creek Mine Adjustment	Repowering Projects Capital Addition	EV 2020 Capital Addition	Cholla Unit 4 Retirement
1 Operating Revenues:								
2 General Business Revenues	-	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-	-
5 Other Operating Revenues	4,630,292	-	-	-	-	-	-	-
6 Total Operating Revenues	4,630,292	-	-	-	-	-	-	-
7								
8 Operating Expenses:								
9 Steam Production	-	-	-	-	1,305,530	-	-	(7,887,593)
10 Nuclear Production	-	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-	-
12 Other Power Supply	-	(77,714)	-	-	-	24,949	4,094,942	-
13 Transmission	-	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-	-
18 Administrative & General	-	(337,569)	-	-	(2,926,596)	-	-	-
19								
20 Total O&M Expenses	-	(415,283)	-	-	(1,621,067)	24,949	4,094,942	(7,887,593)
21	-	-	-	-	-	-	-	-
22 Depreciation	-	-	(1,447,151)	-	-	13,454,031	19,280,443	(6,690,160)
23 Amortization	-	-	(1,795,238)	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-	-	-	-
25 Income Taxes - Federal	(974)	1,372,707	317,160	301,002	(1,423,075)	(5,798,187)	(15,816,835)	1,810,607
26 Income Taxes - State	(221)	310,880	71,828	68,169	(322,287)	(1,313,129)	(3,582,075)	410,052
27 Income Taxes - Def Net	1,138,428	(1,446,871)	441,384	-	2,150,491	3,411,689	10,922,012	1,644,883
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-	-
30								
31 Total Operating Expenses:	1,137,233	(178,568)	(2,412,017)	369,170	(1,215,938)	9,779,353	14,898,487	(10,712,211)
32								
33 Operating Rev For Return:	3,493,058	178,568	2,412,017	(369,170)	1,215,938	(9,779,353)	(14,898,487)	10,712,211
34								
35 Rate Base:								
36 Electric Plant In Service	-	(52,556,663)	-	-	-	278,134,317	520,861,050	(142,916,286)
37 Plant Held for Future Use	-	-	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	(118,334,759)	(878,862)	-	-	-
39 Elec Plant Acq Adj	(2,488,575)	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	(676,399)	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-	-	(1,723,272)
44 Working Capital	(11)	11,988	3,677	3,489	(31,819)	(66,980)	(144,653)	(53,564)
45 Weatherization Loans	-	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-	-
47								
48 Total Electric Plant:	(2,488,587)	(52,544,675)	3,677	(119,007,669)	(910,681)	278,067,337	520,716,397	(144,693,122)
49	-	-	-	-	-	-	-	-
50 Rate Base Deductions:	-	-	-	-	-	-	-	-
51 Accum Prov For Deprec	-	18,337,869	-	-	-	(198,226,193)	(5,818,318)	94,709,923
52 Accum Prov For Amort	-	-	-	-	-	-	-	-
53 Accum Def Income Tax	2,707,772	11,746,394	1,986,247	24,502,881	(293,634)	(4,135,280)	(12,877,064)	(1,644,883)
54 Unamortized ITC	-	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	(8,078,569)	26,766,048	-	-	-	-
58	-	-	-	-	-	-	-	-
59 Total Rate Base Deductions	2,707,772	30,084,263	(6,092,322)	51,268,929	(293,634)	(202,361,472)	(18,695,383)	93,065,040
60								
61 Total Rate Base:	219,185	(22,460,412)	(6,088,646)	(67,738,740)	(1,204,316)	75,705,864	502,021,014	(51,628,082)
62								
63 Return on Rate Base	0.092%	0.054%	0.078%	0.145%	0.036%	-0.435%	-1.315%	0.340%
64								
65 Return on Equity	0.172%	0.102%	0.146%	0.271%	0.067%	-0.813%	-2.458%	0.635%
66								
67 TAX CALCULATION:								
68 Operating Revenue	4,630,292	415,283	3,242,388	-	1,621,067	(13,478,980)	(23,375,385)	14,577,753
69 Other Deductions	-	-	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-	-
71 Interest	4,859	(497,862)	(134,962)	(1,501,510)	(26,695)	1,678,111	11,127,893	(1,144,398)
72 Schedule "M" Additions	-	(1,783,725)	-	-	1,769,003	7,667,380	19,280,443	(6,690,160)
73 Schedule "M" Deductions	4,630,292	(7,718,158)	1,795,238	-	10,515,600	21,433,833	63,677,502	-
74 Income Before Tax	(4,859)	6,847,578	1,582,113	1,501,510	(7,098,835)	(28,923,543)	(78,900,337)	9,031,991
75								
76 State Income Taxes	(221)	310,880	71,828	68,169	(322,287)	(1,313,129)	(3,582,075)	410,052
77 Taxable Income	(4,638)	6,536,698	1,510,285	1,433,341	(6,776,548)	(27,610,415)	(75,318,262)	8,621,939
78								
79 Federal Income Taxes + Other	(974)	1,372,707	317,160	301,002	(1,423,075)	(5,798,187)	(15,816,835)	1,810,607
APPROXIMATE PRICE CHANGE	(4,765,100)	(2,608,161)	(3,946,984)	(6,621,732)	(1,793,489)	21,371,316	73,247,265	(20,116,471)

Pacificorp
Oregon General Rate Case - December 2021
Tab 8 Adjustment Summary

		8.16
		Klamath Facilities Capital Additions
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	167,031
23	Amortization	-
24	Taxes Other Than Income	-
25	Income Taxes - Federal	(9,924)
26	Income Taxes - State	(2,248)
27	Income Taxes - Def Net	(33,366)
28	Investment Tax Credit Adj.	-
29	Misc Revenue & Expense	-
30		
31	Total Operating Expenses:	121,493
32		
33	Operating Rev For Return:	(121,493)
34		
35	Rate Base:	
36	Electric Plant In Service	835,155
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	(115)
45	Weatherization Loans	-
46	Misc Rate Base	-
47		
48	Total Electric Plant:	835,040
49		-
50	Rate Base Deductions:	-
51	Accum Prov For Deprec	(47,927)
52	Accum Prov For Amort	-
53	Accum Def Income Tax	33,366
54	Unamortized ITC	-
55	Customer Adv For Const	-
56	Customer Service Deposits	-
57	Misc Rate Base Deductions	-
58		-
59	Total Rate Base Deductions	(14,561)
60		
61	Total Rate Base:	820,479
62		
63	Return on Rate Base	-0.004%
64		
65	Return on Equity	-0.008%
66		
67	TAX CALCULATION:	
68	Operating Revenue	(167,031)
69	Other Deductions	-
70	Interest (AFUDC)	-
71	Interest	18,187
72	Schedule "M" Additions	167,031
73	Schedule "M" Deductions	31,318
74	Income Before Tax	(49,505)
75		
76	State Income Taxes	(2,248)
77	Taxable Income	(47,257)
78		
79	Federal Income Taxes + Other	(9,924)
	APPROXIMATE PRICE CHANGE	252,873

PacifiCorp
Oregon General Rate Case - December 2021
Cash Working Capital

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Cash Working Capital	CWC	3	(883,425)	OR	Situs	(883,425)	Below
Adjustment Detail:							
Cash Working Capital June 2019 - Unadjusted			30,507,590			8,591,673	2.28
Cash Working Capital December 2021 - Normalized			26,692,729			7,708,249	2.28
Adjustment:			(3,814,861)			(883,425)	

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, 2021

	Total	California	Oregon	Washington	Wyoming	Wy-PPL	Utah	Idaho	Wy-UPL	FERC
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	2,763,632,596	57,837,067	731,108,582	204,548,505	392,916,756	319,615,745	1,191,215,618	167,759,268	73,301,011	709,019
Taxes Other than Income	232,642,537	5,593,705	86,353,112	15,157,196	28,715,478	23,730,936	85,494,154	11,288,646	4,984,542	40,246
Federal Income Tax	(57,431,087)	(1,150,941)	(10,587,018)	(8,288,041)	(7,873,929)	(4,811,419)	(37,229,447)	(3,402,180)	(3,062,511)	2,572,727
State Income Tax	29,409,617	391,151	8,640,100	1,470,473	4,420,328	3,921,271	10,230,587	1,731,008	499,058	594,672
Total	2,968,253,663	62,670,982	815,514,776	212,888,133	418,178,633	342,456,533	1,249,710,912	177,376,742	75,722,100	3,916,664
Divided by Days in Year	365	365	365	365	365	365	365	365	365	365
Avg. Daily Cost of Service	8,132,202	171,701	2,234,287	583,255	1,145,695	938,237	3,423,866	485,964	207,458	10,731
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	**26,692,729**	157,829	**7,708,249**	3,540,359	1,018,634	834,183	13,929,591	332,389	184,450	5,679
	Ref. 2.28		**Ref. 2.28**							

PacifiCorp
Oregon General Rate Case - December 2021
Trapper Mine Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Tangible Property	399	1	7,201,655	SE	25.101%	1,807,722	Below
Other Tangible Property	399	3	(1,165,425)	SE	25.101%	(292,539)	Below
			6,036,229			1,515,183	Below
Final Reclamation Liability	2533	3	(478,796)	SE	25.101%	(120,185)	Below
Adjustment to Tax:							
Schedule M Adj - Reclamation Liab	SCHMAT	3	235,509	SE	25.101%	59,116	8.2.2
Deferred Income Tax Expense	41110	3	(57,903)	SE	25.101%	(14,535)	8.2.2
Accumulated Def Inc Tax Balance	190	3	99,589	SE	25.101%	24,998	8.2.2

Adjustment Detail

	TOTAL COMPANY	REF#
Other Tangible Property		
June 2019 End of Period Balance	7,201,655	8.2.1
December 2020 End of Period Balance	6,036,229	8.2.1
Adjust to December 2020 End of Period Balance	(1,165,425)	Above
Final Reclamation Liability		
June 2019 12 Mth. Average	(6,512,893)	8.2.2
December 2020 12 Mth. Average	(6,991,690)	8.2.2
Adjust to December 2020 12 Mth. Average	(478,796)	Above

Description of Adjustment:

The Company owns a 21.40% 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 2020. 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 2021
Trapper Mine Rate Base

DESCRIPTION	Jul-18 Actual	Aug-18 Actual	Sep-18 Actual	Oct-18 Actual	Nov-18 Actual	Dec-18 Actual	Jan-19 Actual	Feb-19 Actual	Mar-19 Actual	Apr-19 Actual	May-19 Actual	Jun-19 Actual
Property, Plant, and Equipment												
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
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
Equipment and Facilities	130,133,762	129,864,875	129,871,017	130,193,843	130,441,539	131,436,326	131,444,798	131,815,797	131,839,368	131,900,162	131,802,049	129,647,551
Total Property, Plant, and Equipment	150,717,561	150,448,674	150,454,816	150,777,642	151,025,338	152,020,125	152,028,597	152,399,596	152,423,167	152,483,961	152,385,848	150,231,350
Accumulated Depreciation	(120,641,613)	(120,799,407)	(121,373,783)	(121,894,334)	(122,342,644)	(122,843,808)	(123,335,248)	(123,807,137)	(124,389,415)	(124,860,891)	(125,221,277)	(123,345,936)
Total Property, Plant, and Equipment	30,075,948	29,649,267	29,081,033	28,883,308	28,682,694	29,176,317	28,693,349	28,592,459	28,033,752	27,623,070	27,164,571	26,885,414
Other												
Inventories	5,547,897	6,244,181	6,645,821	6,529,793	5,873,119	6,388,403	5,728,066	5,714,021	6,278,600	6,383,070	6,755,971	5,804,961
Prepaid Expenses	6,063,412	5,458,214	5,026,844	4,956,612	4,283,383	3,889,048	3,113,866	2,558,627	2,097,572	1,565,430	1,109,891	382,217
Restricted Funds: Self-bonding for Black Lung	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Deferred GE Royalty Amount	-	-	-	-	-	-	-	-	-	-	-	-
Advance Royalty - State 206-13	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	80,000	80,000
Total Other	12,181,309	12,272,395	12,242,665	12,056,405	10,726,502	10,847,451	9,411,932	8,842,648	8,946,172	8,518,500	8,445,862	6,767,178
Total Rate Base	42,257,257	41,921,662	41,323,698	40,939,713	39,409,196	40,023,768	38,105,281	37,435,107	36,979,924	36,141,570	35,610,433	33,652,592
PacifiCorp Share (21.40%)	**9,043,053**	**8,971,236**	**8,843,271**	**8,761,099**	**8,433,568**	**8,565,086**	**8,154,530**	**8,011,113**	**7,913,704**	**7,734,296**	**7,620,633**	**7,201,655**

DESCRIPTION	Jan-20 Forecast	Feb-20 Forecast	Mar-20 Forecast	Apr-20 Forecast	May-20 Forecast	Jun-20 Forecast	Jul-20 Forecast	Aug-20 Forecast	Sep-20 Forecast	Oct-20 Forecast	Nov-20 Forecast	Dec-20 Forecast
Property, Plant, and Equipment												
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
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
Equipment and Facilities	133,677,945	133,603,856	133,529,766	133,455,677	133,381,587	133,307,498	133,233,408	133,159,318	133,085,229	133,011,139	132,937,050	132,862,960
Total Property, Plant, and Equipment	154,261,744	154,187,655	154,113,565	154,039,476	153,965,386	153,891,297	153,817,207	153,743,117	153,669,028	153,594,938	153,520,849	153,446,759
Accumulated Depreciation	(130,175,955)	(130,489,454)	(130,802,954)	(131,116,454)	(131,429,954)	(131,743,454)	(132,056,954)	(132,370,454)	(132,683,954)	(132,997,454)	(133,310,954)	(133,624,454)
Total Property, Plant, and Equipment	24,085,790	23,698,200	23,310,611	22,923,021	22,535,432	22,147,842	21,760,253	21,372,663	20,985,074	20,597,484	20,209,895	19,822,305
Other												
Inventories	8,000,000	8,000,000	8,000,000	8,000,000	8,000,000	8,000,000	8,000,000	8,000,000	8,000,000	8,000,000	8,000,000	8,000,000
Prepaid Expenses	362,866	343,514	324,163	304,811	285,460	266,109	246,757	227,406	208,054	188,703	169,351	150,000
Restricted Funds: Self-bonding for Black Lung	234,374	234,374	234,374	234,374	234,374	234,374	234,374	234,374	234,374	234,374	234,374	234,374
Deferred GE Royalty Amount	-	-	-	-	-	-	-	-	-	-	-	-
Advance Royalty - State 206-13	-	-	-	-	-	-	-	-	-	-	-	-
Total Other	8,597,240	8,577,888	8,558,537	8,539,185	8,519,834	8,500,483	8,481,131	8,461,780	8,442,428	8,423,077	8,403,725	8,384,374
Total Rate Base	32,683,029	32,276,089	31,869,148	31,462,207	31,055,266	30,648,325	30,241,384	29,834,443	29,427,502	29,020,561	28,613,620	28,206,679
PacifiCorp Share (21.40%)	**6,994,168**	**6,907,083**	**6,819,998**	**6,732,912**	**6,645,827**	**6,558,742**	**6,471,656**	**6,384,571**	**6,297,485**	**6,210,400**	**6,123,315**	**6,036,229**

June 2019 End of Period Balance	**7,201,655**	**Ref 8.2**
December 2020 End of Period Balance	**6,036,229**	**Ref 8.2**

PacifiCorp
Oregon General Rate Case - December 2021
Trapper Mine
Final Reclamation Liability

Actuals

Description:	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
Final Reclamation Liability	(6,401,515)	(6,423,370)	(6,437,021)	(6,458,977)	(6,485,177)	(6,498,181)	(6,525,338)	(6,546,584)	(6,564,122)	(6,584,388)	(6,601,912)	(6,628,138)

Forecast

Description:	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Final Reclamation Liability	(6,991,690)	(6,991,690)	(6,991,690)	(6,991,690)	(6,991,690)	(6,991,690)	(6,991,690)	(6,991,690)	(6,991,690)	(6,991,690)	(6,991,690)	(6,991,690)

End of Period Balance:

June 2019 12 Mth. Average	(6,512,893)	
December 2020 12 Mth. Average	(6,991,690)	
Adjustment to Rate Base	(478,796)	Ref 8.2

Adjustments for Tax:
Change in Liability Account Balance:

Schedule M Add - Pro Forma	**363,552**	
Schedule M Add - Forecast Period	128,043	
Adjustment needed	**235,509**	**Ref 8.2**
Def Inc Tax Exp - Pro Forma	**(89,385)**	
Def Inc Tax Exp - Forecast Period	(31,482)	
Adjustment needed	**(57,903)**	**Ref 8.2**

ADIT Adjustment for Tax:

Actuals Account 287216 (FERC Account 190) M#605.715:

Description:	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
Trapper Mine Contract Obligation	1,532,345	1,537,718	1,542,364	1,547,762	1,554,204	1,562,198	1,568,875	1,574,099	1,579,684	1,584,667	1,588,975	1,596,077

Forecast

Description:	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Trapper Mine Contract Obligation	1,659,353	1,719,019	1,719,019	1,719,019	1,719,019	1,719,019	1,719,019	1,719,019	1,719,019	1,719,019	1,719,019	1,719,019	1,719,019

End of Period Balance:

Forecast 2021 13 Mth Average	1,614,840	
December 2020 13 Mth. Average	1,714,429	
Adjustment to Rate Base	**99,589**	**Ref 8.2**

PacifiCorp
Oregon General Rate Case - December 2021
Jim Bridger Mine Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Tangible Property	399	1	99,000,229	SE	25.101%	24,850,531	Below
Other Tangible Property	399	3	(22,151,459)	SE	25.101%	(5,560,346)	Below
			76,848,770			19,290,185	
Adjustment to Tax:							
Accumulated Def Inc Tax Balance	190	3	618,004	SE	25.101%	155,128	8.3.2

Adjustment Detail

June 2019 End of Period Balance	99,000,229	8.3.1
December 2020 End of Period Balance	76,848,770	8.3.1
Adjustment to December 2020 Balance	(22,151,459)	

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 2021
Jim Bridger Mine Rate Base
End of Period
(000's)

Bridger Total	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
Description	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**
1 Structure, Equipment, Mine Dev.	450,708	451,262	451,775	450,784	451,137	446,778	447,148	447,276	447,260	446,039	445,802	442,931	442,864
2 Materials & Supplies	17,074	16,693	16,574	16,259	15,821	15,986	15,983	16,275	16,046	16,178	16,170	16,299	16,432
4 Pit Inventory	45,462	44,834	41,254	42,435	38,151	35,961	29,203	25,750	21,201	18,577	20,066	23,024	26,673
5 Deferred Long Wall Costs	1,527	1,387	1,048	777	602	376	2,521	3,495	2,201	2,058	2,052	2,848	2,765
6 Reclamation Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Accumulated Depreciation	(322,901)	(324,943)	(327,332)	(328,598)	(330,580)	(329,063)	(330,770)	(332,867)	(335,146)	(336,185)	(338,361)	(337,895)	(340,234)
8 Bonus Bid / Lease Payable	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL RATE BASE	191,870	189,233	183,320	181,657	175,132	170,037	164,085	159,929	151,562	146,668	145,728	147,206	148,500
PacifiCorp Share (66.67%)	**127,914**	**126,155**	**122,213**	**121,104**	**116,754**	**113,358**	**109,390**	**106,620**	**101,042**	**97,779**	**97,152**	**98,137**	**99,000**

Bridger Total	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma
Description	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**
1 Structure, Equipment, Mine Dev.	444,058	444,093	444,119	444,181	444,202	444,243	444,305	444,525	444,748	446,052	446,551	448,129	448,540
2 Materials & Supplies	15,242	15,287	15,078	14,868	14,658	14,449	14,239	14,029	13,820	13,610	13,217	13,024	12,813
4 Pit Inventory	27,713	23,583	25,994	28,552	32,713	37,147	41,757	39,409	35,375	31,866	31,399	29,000	29,604
5 Deferred Long Wall Costs	5,287	4,635	4,136	3,484	2,816	1,815	893	908	5,087	4,566	3,905	3,366	2,939
6 Reclamation Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Accumulated Depreciation	(351,504)	(353,871)	(356,191)	(358,389)	(360,678)	(363,075)	(365,664)	(367,914)	(369,773)	(372,005)	(374,286)	(376,497)	(378,623)
8 Bonus Bid / Lease Payable	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL RATE BASE	140,796	133,728	133,136	132,697	133,711	134,579	135,530	130,957	129,257	124,090	120,786	117,023	115,273
PacifiCorp Share (66.67%)	**93,864**	**89,152**	**88,757**	**88,464**	**89,141**	**89,720**	**90,353**	**87,305**	**86,171**	**82,727**	**80,524**	**78,015**	**76,849**

June 2019 - End of Period Balance	**99,000**	**Ref 8.3**
December 2020 - End of Period Balance	**76,849**	**Ref 8.3**

PacifiCorp
Oregon General Rate Case - December 2021
Jim Bridger Mine Rate Base
End of Period
(000's)

	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Materials & Supplies:													
Obsolete Reserve - Surface	(300,699)	(317,365)	(334,032)	(350,699)	(367,365)	(384,032)	(400,699)	(417,365)	(434,032)	(450,699)	(650,699)	(650,699)	(668,564)
Obsolete Reserve - Underground	(785,809)	(978,809)	(1,171,809)	(1,364,809)	(1,557,809)	(1,750,809)	(1,943,809)	(2,136,809)	(2,329,809)	(2,522,809)	(2,715,809)	(2,908,809)	(3,101,809)
Total Obsolete Reserves	(1,086,507)	(1,296,174)	(1,505,841)	(1,715,507)	(1,925,174)	(2,134,841)	(2,344,507)	(2,554,174)	(2,763,841)	(2,973,507)	(3,366,507)	(3,559,507)	(3,770,372)
PacifiCorp's 2/3 share:													
Obsolete Reserve - Surface	(200,466)	(211,577)	(222,688)	(233,799)	(244,910)	(256,021)	(267,132)	(278,243)	(289,355)	(300,466)	(433,799)	(433,799)	(445,709)
Obsolete Reserve - Underground	(523,872)	(652,539)	(781,206)	(909,872)	(1,038,539)	(1,167,206)	(1,295,872)	(1,424,539)	(1,553,206)	(1,681,872)	(1,810,539)	(1,939,206)	(2,067,872)
Total of PacifiCorp's share of Obsolete Reserves	(724,338)	(864,116)	(1,003,894)	(1,143,671)	(1,283,449)	(1,423,227)	(1,563,004)	(1,702,782)	(1,842,561)	(1,982,338)	(2,244,338)	(2,373,005)	**(2,513,581)**

ADIT 190 Balance at December 31, 2020 **618,004** **Ref 8.3**

PacifiCorp
Oregon General Rate Case - December 2021
Customer Advances for Construction

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Customer Advances	252	1	(30,809)	CA	Situs	-	8.4.1
Customer Advances	252	1	(1,721,216)	OR	Situs	(1,721,216)	8.4.1
Customer Advances	252	1	(578,667)	WA	Situs	-	8.4.1
Customer Advances	252	1	(754,457)	ID	Situs	-	8.4.1
Customer Advances	252	1	(12,410,503)	UT	Situs	-	8.4.1
Customer Advances	252	1	(804,314)	WYP	Situs	-	8.4.1
Customer Advances	252	1	16,299,967	SG	26.023%	4,241,680	8.4.1
Total			-			2,520,464	

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.

PacifiCorp
Oregon General Rate Case - December 2021
Customer Advances for Construction

END OF PERIOD BALANCES:

Account	Booked Allocation	Correct Allocation	Adjustment	Ref.
252CA	-	(30,809)	**(30,809)**	**Page 8.4**
252OR	(919,079)	(2,640,295)	**(1,721,216)**	**Page 8.4**
252WA	-	(578,667)	**(578,667)**	**Page 8.4**
252IDU	-	(754,457)	**(754,457)**	**Page 8.4**
252UT	(1,209,478)	(13,619,982)	**(12,410,503)**	**Page 8.4**
252WYP	-	(804,314)	**(804,314)**	**Page 8.4**
252SG	(35,071,052)	(18,771,085)	**16,299,967**	**Page 8.4**
Total	**(37,199,609)**	**(37,199,609)**	**-**	

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Plant	312	3	(9,035,332)	SG	26.023%	(2,351,231)	
Steam Plant	312	3	(12,666,409)	SG	26.023%	(3,296,133)	
Steam Plant	312	3	120,137,241	SG	26.023%	31,262,873	
Steam Plant	312	3	(2,762,573)	SG	26.023%	(718,894)	
Hydro Plant	332	3	(29,973,957)	SG	26.023%	(7,800,013)	
Hydro Plant	332	3	(299,898)	SG	26.023%	(78,041)	
Hydro Plant	332	3	64,834,906	SG-P	26.023%	16,871,749	
Hydro Plant	332	3	14,934,525	SG-U	26.023%	3,886,357	
Other Plant	343	3	-	SG	26.023%	-	
Other Plant	343	3	30,376,033	SG	26.023%	7,904,644	
Other Plant	343	3	129,823	OR	Situs	129,823	
Other Plant	343	3	(788,972,444)	SG-W	26.023%	(205,311,400)	
Other Plant	343	3	98,649	SG	26.023%	25,671	
Transmission Plant	355	3	(3,285,630)	SG	26.023%	(855,007)	
Transmission Plant	355	3	(6,758,020)	SG	26.023%	(1,758,615)	
Transmission Plant	355	3	378,024,647	SG	26.023%	98,371,965	
Distribution Plant	360	3	4,532,263	OR	Situs	1,235,048	
Distribution Plant	361	3	8,683,178	OR	Situs	2,366,178	
Distribution Plant	362	3	72,906,185	OR	Situs	19,867,039	
Distribution Plant	364	3	87,746,195	OR	Situs	23,910,963	
Distribution Plant	365	3	55,820,826	OR	Situs	15,211,255	
Distribution Plant	366	3	27,685,920	OR	Situs	7,544,453	
Distribution Plant	367	3	64,636,252	OR	Situs	17,613,471	
Distribution Plant	368	3	99,551,493	OR	Situs	27,127,924	
Distribution Plant	369	3	59,612,573	OR	Situs	16,244,511	
Distribution Plant	370	3	16,868,904	OR	Situs	4,596,800	
Distribution Plant	371	3	625,965	OR	Situs	170,576	
Distribution Plant	373	3	4,454,768	OR	Situs	1,213,931	
General Plant	397	3	4,221,163	CA	Situs	-	
General Plant	397	3	18,336,747	OR	Situs	18,336,747	
General Plant	397	3	1,354,438	WA	Situs	-	
General Plant	397	3	6,027,961	WYP	Situs	-	
General Plant	397	3	39,192,530	UT	Situs	-	
General Plant	397	3	5,950,004	ID	Situs	-	
General Plant	397	3	(507,171)	WYU	Situs	-	
General Plant	397	3	(241,632)	SG	26.023%	(62,879)	
General Plant	397	3	(202,408)	SG	26.023%	(52,672)	
General Plant	397	3	11,783,211	SG	26.023%	3,066,302	
General Plant	397	3	18,189,475	SO	27.215%	4,950,322	
General Plant	397	3	(191,169)	SG	26.023%	(49,747)	
General Plant	397	3	(239)	SG	26.023%	(62)	
General Plant	397	3	(2,812,019)	CN	31.217%	(877,830)	
General Plant	397	3	(51,850)	SE	25.101%	(13,015)	
Mining Plant	399	3	-	SE	25.101%	-	
			358,955,126			98,683,064	

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, 2020. This adjustment includes the year end balance of the plant additions that will be placed into service by December 31, 2020. 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 8.5.27 through 8.5.30. Retirements of plant in service are also walked forward through the test period. This adjustment includes the repowering retirements. This adjustment reflects the net impact of capital additions, and retirements. The related tax impact is included in adjsutments 7.4 and 7.5.

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Intangible Plant	303	3	636,932	CA	Situs	-	
Intangible Plant	303	3	(613,062)	CN	31.217%	(191,380)	
Intangible Plant	302	3	-	SG	26.023%	-	
Intangible Plant	302	3	-	SG	26.023%	-	
Intangible Plant	303	3	(1,552)	ID	Situs	-	
Intangible Plant	303	3	873,840	OR	Situs	873,840	
Intangible Plant	303	3	(1,106,269)	SE	25.101%	(277,690)	
Intangible Plant	302	3	(6,109,166)	SG	26.023%	(1,589,766)	
Intangible Plant	302	3	(240,294)	SG-P	26.023%	(62,531)	
Intangible Plant	302	3	-	SG-U	26.023%	-	
Intangible Plant	303	3	-	SG	26.023%	-	
Intangible Plant	303	3	17,466,783	SO	27.215%	4,753,639	
Intangible Plant	303	3	(24,922)	UT	Situs	-	
Intangible Plant	303	3	-	WA	Situs	-	
Intangible Plant	303	3	(241,316)	WYP	Situs	-	
Intangible Plant	303	3	-	WYU	Situs	-	
			10,640,974			3,506,113	
		Total	369,596,101			102,189,177	8.5.3

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, 2020. This adjustment includes the year end balance of the plant additions that will be placed into service by December 31, 2020. 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 8.5.27 through 8.5.30. Retirements of plant in service are also walked forward through the test period. This adjustment includes the repowering retirements. This adjustment reflects the net impact of capital additions, and retirements. The related tax impact is included in adjustments 7.4 and 7.5.

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Description	Account	Factor	End of Period June 2019 EPIS Balance	Test Period EPIS Balance (End of Period)	Adjustment to Test Period
Steam Production Plant:					
Pre-merger Pacific	312	SG	1,018,815,063	1,009,779,731	(9,035,332)
Pre-merger Utah	312	SG	1,064,276,771	1,051,610,361	(12,666,409)
Post-merger	312	SG	4,685,212,673	4,805,349,914	120,137,241
Post-merger - Cholla	312	SG	551,962,526	549,199,953	(2,762,573)
Total Steam Plant			7,320,267,032	7,415,939,959	95,672,927
Hydro Production Plant:					
Pre-merger Pacific	332	SG	213,685,360	183,711,403	(29,973,957)
Pre-merger Utah	332	SG	40,795,051	40,495,153	(299,898)
Post-merger	332	SG-P	681,406,110	746,241,015	64,834,906
Post-merger	332	SG-U	140,952,672	155,887,197	14,934,525
Total Hydro Plant			1,076,839,193	1,126,334,768	49,495,575
Other Production Plant:					
Pre-merger Utah	343	SG	235,129	235,129	-
Post-merger	343	SG	1,921,267,427	1,951,643,461	30,376,033
Post-merger Wind	343	SG-W	1,823,644,536	1,034,672,092	(788,972,444)
Black Cap Solar	343	OR	74,986	204,809	129,823
Post-merger	343	SG	85,640,221	85,738,870	98,649
Total Other Production Plant			3,830,862,300	3,072,494,362	(758,367,937)
Transmission Plant:					
Pre-merger Pacific	355	SG	484,060,575	480,774,945	(3,285,630)
Pre-merger Utah	355	SG	625,566,830	618,808,809	(6,758,020)
Post-merger	355	SG	5,336,746,458	5,714,771,105	378,024,647
Total Transmission Plant			6,446,373,863	6,814,354,859	367,980,997
Distribution Plant:					
California	360-373	CA	277,722,065	312,274,943	34,552,879
Oregon	360-373	OR	2,153,746,612	2,290,848,762	137,102,150
Washington	360-373	WA	523,567,016	551,435,929	27,868,913
Eastern Wyoming	360-373	WYP	632,340,852	678,547,698	46,206,846
Utah	360-373	UT	3,051,625,177	3,279,501,681	227,876,504
Idaho	360-373	ID	362,463,738	392,387,444	29,923,706
Western Wyoming	360-373	WYU	137,121,106	136,714,629	(406,477)
Total Distribution Plant			7,138,586,565	7,641,711,087	503,124,522
General Plant:					
California	397	CA	19,537,001	23,758,164	4,221,163
Oregon	397	OR	211,820,507	230,157,254	18,336,747
Washington	397	WA	48,303,495	49,657,933	1,354,438
Eastern Wyoming	397	WYP	80,511,288	86,539,249	6,027,961
Utah	397	UT	227,046,083	266,238,613	39,192,530
Idaho	397	ID	44,890,836	50,840,840	5,950,004
Western Wyoming	397	WYU	16,921,267	16,414,096	(507,171)
Pre-merger Pacific	397	SG	1,173,782	932,150	(241,632)
Pre-merger Utah	397	SG	4,137,040	3,934,632	(202,408)
Post-merger	397	SG	286,417,469	298,200,680	11,783,211
General Office	397	SO	310,565,892	328,755,367	18,189,475
General Office	397	SG	4,904,100	4,712,932	(191,169)
General Office	397	SG	223,232	222,994	(239)
Customer Service	397	CN	17,307,919	14,495,900	(2,812,019)
Fuel Related	397	SE	3,682,952	3,631,101	(51,850)
Total General Plant			1,277,442,861	1,378,491,903	101,049,043

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Description	Account	Factor	End of Period June 2019 EPIS Balance	Test Period EPIS Balance (End of Period)	Adjustment to Test Period
Mining Plant:					
Coal Mine	399	SE	1,854,828	1,854,828	-
Total Mining Plant			1,854,828	1,854,828	-
Intangible Plant:					
California	303	CA	481,167	1,118,099	636,932
Customer Service	303	CN	176,107,084	175,494,022	(613,062)
Pre-merger Utah	302	SG	600,993	600,993	-
Pre-merger Pacific	302	SG	-	-	-
Idaho	303	ID	4,371,145	4,369,593	(1,552)
Oregon	303	OR	4,615,241	5,489,081	873,840
Fuel Related	303	SE	-	(1,106,269)	(1,106,269)
Post-merger	302	SG	177,929,848	171,820,682	(6,109,166)
Hydro Relicensing	302	SG-P	175,244,590	175,004,296	(240,294)
Hydro Relicensing	302	SG-U	9,350,399	9,350,399	-
Post-merger	303	SG	-	-	-
General Office	303	SO	385,727,443	403,194,225	17,466,783
Utah	303	UT	(26,190,998)	(26,215,920)	(24,922)
Washington	303	WA	2,036,363	2,036,363	-
Eastern Wyoming	303	WYP	5,628,211	5,386,895	(241,316)
Western Wyoming	303	WYU	-	-	-
Total Intangible Plant			915,901,485	926,542,460	10,640,974
Total EPIS Balance			28,008,128,127	28,377,724,228	369,596,101
				Ref. 8.5.17	**Ref 8.5.1**

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PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Jun 2019	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2019	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2019	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG									
Geothermal - Blundell	SG									
Pollution Control Equipment	SG									
Pollution Control Equipment	SG									
Pollution Control Equipment	SG									
Post-merger - Cholla	SG									
Total Steam Plant										
Hydro Production Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG-P									
Post-merger	SG-U									
Klamath	SG-P									
Total Hydro Plant										
Other Production Plant:										
Pre-merger Utah	SG	[redacted]								
Post-merger	SG									
Post-merger Wind	SG-W									
Black Cap Solar	OR									
Post-merger	SG									
Total Other Plant										
Transmission Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG									
Total Transmission Plant										
Distribution Plant:										
California	CA	[redacted]								
Oregon	OR									
Washington	WA									
Eastern Wyoming	WYP									
Utah	UT									
Idaho	ID									
Western Wyoming	WYU									
Total Distribution Plant										

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Jun 2019	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2019	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2019	Capital Additions	Retirements
General Plant:										
California	CA	[redacted]								
Oregon	OR									
Washington	WA									
Eastern Wyoming	WYP									
Utah	UT									
Idaho	ID									
Western Wyoming	WYU									
Pre-merger Pacific	SG									
Pre-merger Utah	SG									
Post-merger	SG									
General Office	SO									
General Office	SG									
General Office	SG									
Customer Service	CN									
Fuel Related	SE									
Total General Plant										
Mining Plant:										
Coal Mine	SE	[redacted]								
Total Mining Plant										
Intangible Plant:										
California	CA	[redacted]								
Customer Service	CN									
Pre-merger Utah	SG									
Pre-merger Pacific	SG									
Idaho	ID									
Oregon	OR									
Fuel Related	SE									
Post-merger	SG									
Klamath Hydro Relicensing	SG-P									
Hydro Relicensing	SG-P									
Hydro Relicensing	SG-U									
General Office	SO									
Utah	UT									
Washington	WA									
Eastern Wyoming	WYP									
Western Wyoming	WYU									
Total Intangible Plant										
Total		[redacted]								

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Sep 2019	Capital Additions	Retirements	Adjusted EPIS Balance Oct 2019	Capital Additions	Retirements	Adjusted EPIS Balance Nov 2019	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG									
Geothermal - Blundell	SG									
Pollution Control Equipment	SG									
Pollution Control Equipment	SG									
Pollution Control Equipment	SG									
Post-merger - Cholla	SG									
Total Steam Plant										
Hydro Production Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG-P									
Post-merger	SG-U									
Klamath	SG-P									
Total Hydro Plant										
Other Production Plant:										
Pre-merger Utah	SG	[redacted]								
Post-merger	SG									
Post-merger Wind	SG-W									
Black Cap Solar	OR									
Post-merger	SG									
Total Other Plant										
Transmission Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG									
Total Transmission Plant										
Distribution Plant:										
California	CA	[redacted]								
Oregon	OR									
Washington	WA									
Eastern Wyoming	WYP									
Utah	UT									
Idaho	ID									
Western Wyoming	WYU									
Total Distribution Plant										

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Sep 2019	Capital Additions	Retirements	Adjusted EPIS Balance Oct 2019	Capital Additions	Retirements	Adjusted EPIS Balance Nov 2019	Capital Additions	Retirements
General Plant:										
California	CA	[redacted]								
Oregon	OR									
Washington	WA									
Eastern Wyoming	WYP									
Utah	UT									
Idaho	ID									
Western Wyoming	WYU									
Pre-merger Pacific	SG									
Pre-merger Utah	SG									
Post-merger	SG									
General Office	SO									
General Office	SG									
General Office	SG									
Customer Service	CN									
Fuel Related	SE									
Total General Plant										
Mining Plant:										
Coal Mine	SE	[redacted]								
Total Mining Plant										
Intangible Plant:										
California	CA	[redacted]								
Customer Service	CN									
Pre-merger Utah	SG									
Pre-merger Pacific	SG									
Idaho	ID									
Oregon	OR									
Fuel Related	SE									
Post-merger	SG									
Klamath Hydro Relicensing	SG-P									
Hydro Relicensing	SG-P									
Hydro Relicensing	SG-U									
General Office	SO									
Utah	UT									
Washington	WA									
Eastern Wyoming	WYP									
Western Wyoming	WYU									
Total Intangible Plant										
Total		[redacted]								

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PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Dec 2019	Capital Additions	Retirements	Adjusted EPIS Balance Jan 2020	Capital Additions	Retirements	Adjusted EPIS Balance Feb 2020	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG									
Geothermal - Blundell	SG									
Pollution Control Equipment	SG									
Pollution Control Equipment	SG									
Pollution Control Equipment	SG									
Post-merger - Cholla	SG									
Total Steam Plant										
Hydro Production Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG-P									
Post-merger	SG-U									
Klamath	SG-P									
Total Hydro Plant										
Other Production Plant:										
Pre-merger Utah	SG	[redacted]								
Post-merger	SG									
Post-merger Wind	SG-W									
Black Cap Solar	OR									
Post-merger	SG									
Total Other Plant										
Transmission Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG									
Total Transmission Plant										
Distribution Plant:										
California	CA	[redacted]								
Oregon	OR									
Washington	WA									
Eastern Wyoming	WYP									
Utah	UT									
Idaho	ID									
Western Wyoming	WYU									
Total Distribution Plant										

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PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Dec 2019	Capital Additions	Retirements	Adjusted EPIS Balance Jan 2020	Capital Additions	Retirements	Adjusted EPIS Balance Feb 2020	Capital Additions	Retirements
General Plant:										
California	CA	[redacted]								
Oregon	OR									
Washington	WA									
Eastern Wyoming	WYP									
Utah	UT									
Idaho	ID									
Western Wyoming	WYU									
Pre-merger Pacific	SG									
Pre-merger Utah	SG									
Post-merger	SG									
General Office	SO									
General Office	SG									
General Office	SG									
Customer Service	CN									
Fuel Related	SE									
Total General Plant										
Mining Plant:										
Coal Mine	SE	[redacted]								
Total Mining Plant										
Intangible Plant:										
California	CA	[redacted]								
Customer Service	CN									
Pre-merger Utah	SG									
Pre-merger Pacific	SG									
Idaho	ID									
Oregon	OR									
Fuel Related	SE									
Post-merger	SG									
Klamath Hydro Relicensing	SG-P									
Hydro Relicensing	SG-P									
Hydro Relicensing	SG-U									
General Office	SO									
Utah	UT									
Washington	WA									
Eastern Wyoming	WYP									
Western Wyoming	WYU									
Total Intangible Plant										
Total		[redacted]								

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Mar 2020	Capital Additions	Retirements	Adjusted EPIS Balance Apr 2020	Capital Additions	Retirements	Adjusted EPIS Balance May 2020	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG									
Geothermal - Blundell	SG									
Pollution Control Equipment	SG									
Pollution Control Equipment	SG									
Pollution Control Equipment	SG									
Post-merger - Cholla	SG									
Total Steam Plant										
Hydro Production Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG-P									
Post-merger	SG-U									
Klamath	SG-P									
Total Hydro Plant										
Other Production Plant:										
Pre-merger Utah	SG	[redacted]								
Post-merger	SG									
Post-merger Wind	SG-W									
Black Cap Solar	OR									
Post-merger	SG									
Total Other Plant										
Transmission Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG									
Total Transmission Plant										
Distribution Plant:										
California	CA	[redacted]								
Oregon	OR									
Washington	WA									
Eastern Wyoming	WYP									
Utah	UT									
Idaho	ID									
Western Wyoming	WYU									
Total Distribution Plant										

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PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Mar 2020	Capital Additions	Retirements	Adjusted EPIS Balance Apr 2020	Capital Additions	Retirements	Adjusted EPIS Balance May 2020	Capital Additions	Retirements
General Plant:										
California	CA	[redacted]								
Oregon	OR									
Washington	WA									
Eastern Wyoming	WYP									
Utah	UT									
Idaho	ID									
Western Wyoming	WYU									
Pre-merger Pacific	SG									
Pre-merger Utah	SG									
Post-merger	SG									
General Office	SO									
General Office	SG									
General Office	SG									
Customer Service	CN									
Fuel Related	SE									
Total General Plant										
Mining Plant:										
Coal Mine	SE	[redacted]								
Total Mining Plant										
Intangible Plant:										
California	CA	[redacted]								
Customer Service	CN									
Pre-merger Utah	SG									
Pre-merger Pacific	SG									
Idaho	ID									
Oregon	OR									
Fuel Related	SE									
Post-merger	SG									
Klamath Hydro Relicensing	SG-P									
Hydro Relicensing	SG-P									
Hydro Relicensing	SG-U									
General Office	SO									
Utah	UT									
Washington	WA									
Eastern Wyoming	WYP									
Western Wyoming	WYU									
Total Intangible Plant										
Total		[redacted]								

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Jun 2020	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2020	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2020	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG									
Geothermal - Blundell	SG									
Pollution Control Equipment	SG									
Pollution Control Equipment	SG									
Pollution Control Equipment	SG									
Post-merger - Cholla	SG									
Total Steam Plant										
Hydro Production Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG-P									
Post-merger	SG-U									
Klamath	SG-P									
Total Hydro Plant										
Other Production Plant:										
Pre-merger Utah	SG	[redacted]								
Post-merger	SG									
Post-merger Wind	SG-W									
Black Cap Solar	OR									
Post-merger	SG									
Total Other Plant										
Transmission Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG									
Total Transmission Plant										
Distribution Plant:										
California	CA	[redacted]								
Oregon	OR									
Washington	WA									
Eastern Wyoming	WYP									
Utah	UT									
Idaho	ID									
Western Wyoming	WYU									
Total Distribution Plant										

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Jun 2020	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2020	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2020	Capital Additions	Retirements
General Plant:										
California	CA	[redacted]								
Oregon	OR									
Washington	WA									
Eastern Wyoming	WYP									
Utah	UT									
Idaho	ID									
Western Wyoming	WYU									
Pre-merger Pacific	SG									
Pre-merger Utah	SG									
Post-merger	SG									
General Office	SO									
General Office	SG									
General Office	SG									
Customer Service	CN									
Fuel Related	SE									
Total General Plant										
Mining Plant:										
Coal Mine	SE	[redacted]								
Total Mining Plant										
Intangible Plant:										
California	CA	[redacted]								
Customer Service	CN									
Pre-merger Utah	SG									
Pre-merger Pacific	SG									
Idaho	ID									
Oregon	OR									
Fuel Related	SE									
Post-merger	SG									
Klamath Hydro Relicensing	SG-P									
Hydro Relicensing	SG-P									
Hydro Relicensing	SG-U									
General Office	SO									
Utah	UT									
Washington	WA									
Eastern Wyoming	WYP									
Western Wyoming	WYU									
Total Intangible Plant										
Total		[redacted]								

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Sep 2020	Capital Additions	Retirements	Adjusted EPIS Balance Oct 2020	Capital Additions	Retirements	Adjusted EPIS Balance Nov 2020	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG									
Geothermal - Blundell	SG									
Pollution Control Equipment	SG									
Pollution Control Equipment	SG									
Pollution Control Equipment	SG									
Post-merger - Cholla	SG									
Total Steam Plant										
Hydro Production Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG-P									
Post-merger	SG-U									
Klamath	SG-P									
Total Hydro Plant										
Other Production Plant:										
Pre-merger Utah	SG	[redacted]								
Post-merger	SG									
Post-merger Wind	SG-W									
Black Cap Solar	OR									
Post-merger	SG									
Total Other Plant										
Transmission Plant:										
Pre-merger Pacific	SG	[redacted]								
Pre-merger Utah	SG									
Post-merger	SG									
Total Transmission Plant										
Distribution Plant:										
California	CA	[redacted]								
Oregon	OR									
Washington	WA									
Eastern Wyoming	WYP									
Utah	UT									
Idaho	ID									
Western Wyoming	WYU									
Total Distribution Plant										

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PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Sep 2020	Capital Additions	Retirements	Adjusted EPIS Balance Oct 2020	Capital Additions	Retirements	Adjusted EPIS Balance Nov 2020	Capital Additions	Retirements
General Plant:										
California	CA	[redacted]								
Oregon	OR									
Washington	WA									
Eastern Wyoming	WYP									
Utah	UT									
Idaho	ID									
Western Wyoming	WYU									
Pre-merger Pacific	SG									
Pre-merger Utah	SG									
Post-merger	SG									
General Office	SO									
General Office	SG									
General Office	SG									
Customer Service	CN									
Fuel Related	SE									
Total General Plant										
Mining Plant:										
Coal Mine	SE	[redacted]								
Total Mining Plant										
Intangible Plant:										
California	CA	[redacted]								
Customer Service	CN									
Pre-merger Utah	SG									
Pre-merger Pacific	SG									
Idaho	ID									
Oregon	OR									
Fuel Related	SE									
Post-merger	SG									
Klamath Hydro Relicensing	SG-P									
Hydro Relicensing	SG-P									
Hydro Relicensing	SG-U									
General Office	SO									
Utah	UT									
Washington	WA									
Eastern Wyoming	WYP									
Western Wyoming	WYU									
Total Intangible Plant										
Total		[redacted]								

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Dec 2020	End of Period December 2020 Test Period Balance
Steam Production Plant:			
Pre-merger Pacific	SG	[redacted]	
Pre-merger Utah	SG		
Post-merger	SG		
Geothermal - Blundell	SG		
Pollution Control Equipment	SG		
Pollution Control Equipment	SG		
Pollution Control Equipment	SG		
Post-merger - Cholla	SG		
Total Steam Plant			
Hydro Production Plant:			
Pre-merger Pacific	SG	[redacted]	
Pre-merger Utah	SG		
Post-merger	SG-P		
Post-merger	SG-U		
Klamath	SG-P		
Total Hydro Plant			
Other Production Plant:			
Pre-merger Utah	SG	[redacted]	
Post-merger	SG		
Post-merger Wind	SG-W		
Black Cap Solar	OR		
Post-merger	SG		
Total Other Plant			
Transmission Plant:			
Pre-merger Pacific	SG	[redacted]	
Pre-merger Utah	SG		
Post-merger	SG		
Total Transmission Plant			
Distribution Plant:			
California	CA	[redacted]	
Oregon	OR		
Washington	WA		
Eastern Wyoming	WYP		
Utah	UT		
Idaho	ID		
Western Wyoming	WYU		
Total Distribution Plant			

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Description	Factor	Adjusted EPIS Balance Dec 2020	End of Period December 2020 Test Period Balance
General Plant:			
California	CA	[redacted]	[redacted]
Oregon	OR	[redacted]	[redacted]
Washington	WA	[redacted]	[redacted]
Eastern Wyoming	WYP	[redacted]	[redacted]
Utah	UT	[redacted]	[redacted]
Idaho	ID	[redacted]	[redacted]
Western Wyoming	WYU	[redacted]	[redacted]
Pre-merger Pacific	SG	[redacted]	[redacted]
Pre-merger Utah	SG	[redacted]	[redacted]
Post-merger	SG	[redacted]	[redacted]
General Office	SO	[redacted]	[redacted]
General Office	SG	[redacted]	[redacted]
General Office	SG	[redacted]	[redacted]
Customer Service	CN	[redacted]	[redacted]
Fuel Related	SE	[redacted]	[redacted]
Total General Plant		[redacted]	[redacted]
Mining Plant:			
Coal Mine	SE	[redacted]	[redacted]
Total Mining Plant		[redacted]	[redacted]
Intangible Plant:			
California	CA	[redacted]	[redacted]
Customer Service	CN	[redacted]	[redacted]
Pre-merger Utah	SG	[redacted]	[redacted]
Pre-merger Pacific	SG	[redacted]	[redacted]
Idaho	ID	[redacted]	[redacted]
Oregon	OR	[redacted]	[redacted]
Fuel Related	SE	[redacted]	[redacted]
Post-merger	SG	[redacted]	[redacted]
Klamath Hydro Relicensing	SG-P	[redacted]	[redacted]
Hydro Relicensing	SG-P	[redacted]	[redacted]
Hydro Relicensing	SG-U	[redacted]	[redacted]
General Office	SO	[redacted]	[redacted]
Utah	UT	[redacted]	[redacted]
Washington	WA	[redacted]	[redacted]
Eastern Wyoming	WYP	[redacted]	[redacted]
Western Wyoming	WYU	[redacted]	[redacted]
Total Intangible Plant		[redacted]	[redacted]
Total		[redacted]	[redacted]
			Ref. 8.5.3

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions
Steam Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July19 to Dec20 Plant Adds	Ref.
Huntington U2 Boiler Economizer Replacement w/heade	312	SG	Oct-19	7,169,606	
Dave Johnston U0 - DJ CCR Ash Disposal System	312	SG	Nov-19	6,676,458	
Colstrip 3-4:Pond Chem Water Treatmnt Sy	312	SG	Jul-19	4,670,234	
Hunter 303 East & West Waterwall Repl - CY20	312	SG	Apr-20	4,309,103	
Jim Bridger U4 SCR Catalyst Replacement 20	312	SG	Jun-20	3,563,702	
Naughton NAU3 Convert to Natural Gas 247 MW (IMP)	312	SG	Jun-20	3,249,023	
Hunter 303 HP/IP Turbine Overhaul	312	SG	Apr-20	2,809,848	
Huntington U2 Cooling Tower Cells 1-6 Rebuild	312	SG	Nov-19	2,762,434	
Dave Johnston U1 - Turbine Overhaul - 2020	312	SG	Dec-20	2,701,390	
Blundell U0 Plant and Steam Field Controls Update	312	SG	May-20	2,262,849	
Naughton U2 OH Turbine Major (LP) CY20	312	SG	May-20	2,127,185	
Hunter 303 Nose Arch Upper Tube Repl - CY20	312	SG	Apr-20	1,976,492	
Craig CRGU5 Reliability/Ability To Serve CY20	312	SG	Dec-20	1,907,860	
Hunter 303 Scrubber Component Overhaul	312	SG	Apr-20	1,846,999	
Jim Bridger U4 Burners - Major 20	312	SG	Jun-20	1,752,468	
Huntington U2 Air Preheater Baskets - CY2019	312	SG	Oct-19	1,693,079	
Dave Johnston U0 - MILL BLANKET - 2020	312	SG	Various	1,617,746	
Craig CRGU5 Regulatory Environ & Safety CY20	312	SG	Dec-20	1,483,898	
Hunter 303 Baghouse Reverse Air Duct	312	SG	Apr-20	1,420,554	
Dave Johnston DJ Coal Yard Control System Update	312	SG	Sep-19	1,333,736	
Dave Johnston U0 Mill Blanket 2019	312	SG	Dec-19	1,326,884	
Hunter 303 DCS Simulator Replacement	312	SG	Dec-20	1,321,566	
Dave Johnston Waste Ash Silo Mod w/lTemp Capacity Adde	312	SG	Aug-19	1,311,904	
Dave Johnston U0 - Pumps And Valves - 2020	312	SG	Various	1,307,807	
Blundell U2 Generator Replacement	312	SG	Feb-20	1,266,615	
Jim Bridger U4 Precipitator Wire Replacement 20	312	SG	Jun-20	1,260,841	
Hunter 303 DCS Major Ovation Upgrade - CY20	312	SG	Apr-20	1,250,523	
Jim Bridger U4 Stack Liner (Phase 2) 20	312	SG	Jun-20	1,239,867	
Jim Bridger U4 #43 ABS Coating Phase 2 & Awning Install 20	312	SG	Dec-20	1,208,147	
Huntington U2 Burner Corner Coal Nozzle & Tip repla	312	SG	Oct-19	1,196,787	
Huntington U0 Electric Lake Dam Outlet Upgrade	312	SG	Oct-19	1,176,149	
Huntington U2 Coal Pipe Isolation Valves 1 - 5	312	SG	Nov-19	1,105,889	
JImBridger Blanket - Pumps, Valves, Gearboxes 20	312	SG	Various	1,031,069	
Jim Bridger U4 #41 ABS Coating Phase 2 & Awning Inst	312	SG	Dec-19	1,021,922	
Jim Bridger U2 Transformer Relays - various	312	SG	Mar-20	1,013,188	
Projects Less Than $1million	312	SG	Various	125,832,950	
Projects Less Than $1million - Cholla	312	SSGCH	Various	1,042,250	
Steam Plant Five Year Average Removals	312	SG		(27,552,543)	
				174,696,480	

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions
Hydro Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July19 to Dec20 Plant Adds	Ref.
ILR 4.1.9 Future Fish Passage Stage 1 Ph	332	SG-P	Dec-20	7,945,514	
PP Hydro West	332	SG-P	Various	5,987,500	
PP Hydro Impl On-Proj West	332	SG-P	Dec-19	3,128,470	
Merwin Spillway Gate Wood Extension Repl	332	SG-P	Nov-19	2,929,094	
Oneida 2 Rotor Replacement	332	SG-U	Aug-19	2,882,075	
Lewis River Maximum Flood Improvement St	332	SG-P	Aug-19	2,571,744	
PP Hydro East	332	SG-U	Various	2,472,302	
Swift 1 Minimum Discharge Line	332	SG-P	Nov-20	2,274,365	
PP Hydro Relicensing East	332	SG-U	Nov-19	2,016,840	
Hydro Dam Safety/Safety Emergent 2020	332	SG-P	Nov-20	1,820,815	
Hydro Environmental Emergent 2020	332	SG-P	Various	1,615,236	
Eastside Flowline Removal	332	SG-P	Nov-20	1,312,530	
PP Other Hydro Dam Safety East	332	SG-U	Various	1,263,838	
Weber Relicensing	332	SG-U	Nov-20	1,156,965	
ILR 4.4.1 Swift FSC Pri ScrClr Rebuild	332	SG-P	Dec-20	1,037,555	
Projects Less Than $1million	332	SG-P	Various	10,382,389	
Projects Less Than $1million	332	SG-U	Various	6,255,935	
Hydro Plant Five Year Average Removals	332	SG-U		(759,968)	
Hydro Plant Five Year Average Removals	332	SG-P		(1,355,249)	
				54,937,949	

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions
Other Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Project Description	FERC Account	Factor	Inservice Date	July19 to Dec20 Plant Adds	Ref.
[redacted]					

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions
Transmission Plant Additions

Note: Please see Confidential Exhibit PAC/1309_CONF for redacted information.

Project Description	FERC Account	Factor	Inservice Date	July19 to Dec20 Plant Adds	Ref.
[redacted]					

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions
Distribution Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July19 to Dec20 Plant Adds	Ref.
Utah-New Connect - Residential	364	UT	Various	38,449,921	
PP Distribution OR	364	OR	Various	36,385,682	
Wildfire Mitigation - Dist	364	UT	Various	35,958,000	
Distribution New Revenue Blankets - UT	364	UT	Various	27,402,218	
Distribution Blankets - UT	364	UT	Various	21,533,660	
Oregon-New Connect - Commercial	364	OR	Various	20,131,846	
Utah-New Connect - Commercial	364	UT	Various	19,829,777	
Wildfire Mitigation Plan - OR D	364	OR	Various	16,702,110	8.5.29
Oregon-New Connect - Residential	364	OR	Various	15,788,233	
Lassen Sub-New 69x115 kV sub to replace Mt Shasta Sub(Net 12.5 MVA) I	364	CA	Jun-20	13,052,915	
PP Dist New Connect OR	364	OR	Various	13,012,503	
Distribution New Revenue Blankets - WY	364	WYP	Various	12,695,954	
Wildhorse Resort Phase 2 Load Addition	364	OR	Sep-20	8,860,949	
Naples 138-12.5 kV New Substation TPL	364	UT	Aug-20	8,490,670	
Targeted reliability Improvement, Dist - UT	364	UT	Various	8,266,330	
PP Distribution CA	364	CA	Various	8,076,583	
Wildfire Mitigation Plan - CA D	364	CA	Various	7,882,243	
PP Dist New Connect WA	364	WA	Various	7,868,133	
Draper: Increase Capacity and Convert to 138 kV - ph 2	364	UT	May-20	7,828,230	
Replace Overhead Distribution Poles - UT	364	UT	Various	7,637,954	
Replace Underground Vaults & Equipment - UT	364	UT	Various	7,363,916	
Oregon - Replace OH Dist Lines - Poles	364	OR	Various	5,968,330	
Replace Overhead Distribution Lines - Crossarms & Cutouts - UT Dist	364	UT	Various	5,565,000	
Goshen-Sugarmill-Rigby 161kV Distribution	364	ID	Nov-20	5,559,600	
U/G Cable Test & Replace	364	UT	Various	5,500,000	
Mandated Highway Relocations - UT	364	UT	Various	5,446,693	
Replace Underground Cable - UT	364	UT	Various	4,800,000	
Distribution Blankets - WY	364	WYP	Various	4,728,774	
PP Distribution WA	364	WA	Various	4,723,981	
Replace - Storm & Casualty - UT Dist	364	UT	Various	4,688,009	
New Revenue - Feeder Reinforcement - UT	364	UT	Various	4,554,289	
BioFire Diagnostics, LLC 9 MW Load	364	UT	May-20	4,328,925	
Distribution Blankets - ID	364	ID	Various	4,279,179	
TriMet EV Bus Garage Service Request	364	OR	Dec-20	4,276,053	
Oregon-Replace-Storm and Casualty	364	OR	Various	3,939,926	
Idaho-New Connect - Residential	364	ID	Various	3,908,335	
AMI - Utah Meters 2019 -2020	364	UT	Various	3,901,941	
Oregon - Replace Underground Cable	364	OR	Various	3,850,820	
Washington-New Connect - Commercial	364	WA	Various	3,754,198	
TMP OR Distribution Major Projects - PP	364	OR	Various	3,719,625	
Replace Overhead Distribution Lines - Other - UT	364	UT	Various	3,711,502	
DJ to Thunder Creek Transmission Conversion Ph 2 Jackalope Feeder	364	WYP	Sep-19	3,613,782	
Mobile #6 Replace Failed 138-69kV Transformer	364	UT	Dec-20	3,500,000	
New Connect Meter Purchases - UT	364	UT	Various	3,468,516	
Wyoming-New Connect - Residential	364	WYP	Various	3,100,549	
Glendo T#1 Upgrade Transformer Capacity	364	WYP	Oct-20	2,934,165	
Avian Protection - Dist WY	364	WYP	Various	2,898,666	
Replace Overhead Distribution Lines - Crossarms & Cutouts - WY Dist	364	WYP	Various	2,835,000	
Oregon-Mandated-Neutral Extensions	364	OR	Various	2,823,058	
Wildfire Mitigation Plan - WA D	364	WA	Dec-20	2,652,484	
Washington-New Connect - Residential	364	WA	Various	2,632,642	
Distribution New Revenue Blankets - ID	364	ID	Various	2,622,570	
Oregon-Replace Substation Transformers	364	OR	Various	2,614,659	
Upgrade Distribution Reclosers / Relays UT	364	UT	Various	2,590,467	
Oregon-Replace-Overhead Dist. Lines/othr	364	OR	Various	2,461,817	
Oregon - Mandated Highway Relocations	364	OR	Various	2,298,067	
Wapato Substation Capacity Relief	364	WA	May-20	2,288,057	
Wyoming-New Connect - Commercial	364	WYP	Various	2,216,681	
AMI - Idaho 2019 meters	364	ID	Various	2,124,617	
Oregon - Upgrade - Feeder Improvements	364	OR	Various	2,106,193	
Replace Overhead Distribution Lines - Crossarms & Cutouts - ID Dist	364	ID	Various	2,100,000	
Avian Protection - Dist UT	364	UT	Various	2,066,766	
Avian Protection - Dist ID	364	ID	Various	2,052,271	

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions
Distribution Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July19 to Dec20 Plant Adds	Ref.
Replace Overhead Distribution Poles - ID	364	ID	Various	2,030,381	
Replace Underground Cable - WY	364	WYP	Various	2,000,000	
DJ to Thunder Creek Transmission Conversion Ph 1 Orpha Dis Conversion	364	WYP	Sep-19	2,000,000	
Unspecified OR Distribution Reinforcement	364	OR	Various	1,973,764	
Targeted reliability Improvement, Dist - WY	364	WYP	Various	1,951,126	
Portland UG Network Asset Replacement	364	OR	Various	1,935,281	
California-New Connect - Commercial	364	CA	Various	1,819,651	
Net Metering Installation UT	364	UT	Various	1,758,863	
Replace Overhead Distribution Poles - WY	364	WYP	Various	1,743,176	
Net Metering Meter Purchases - UT	364	UT	Various	1,688,508	
Jordanelle - Midway Construct 138 kV Line Dist Underbuild	364	UT	Sep-20	1,616,713	
Oregon-New Connect - Industrial	364	OR	Various	1,566,782	
Grow Substation - Upgrade Bank #3	364	UT	May-20	1,560,346	
Utah-New Connect - Industrial	364	UT	Various	1,552,889	
Replace Substation Transformers - UT	364	UT	Various	1,537,141	
Oregon - Replace Underground Vaults & Equip	364	OR	Various	1,510,331	
Pole Failure Mitigation - Porcelain Cutout Replacement - UT Dist	364	UT	Various	1,500,000	
Wyoming-New Connect - Industrial	364	WYP	Various	1,465,170	
Grid Resiliency Phase 1 - 230 KV & 500kV Breaker Purchase	364	OR	Dec-20	1,392,598	
Replace - Storm & Casualty - WY Dist	364	WYP	Various	1,377,972	
Washington- Mandated Highway Relocations	364	WA	Various	1,297,159	
Murphy Brown LLC 1.1 MW Load	364	UT	Mar-20	1,151,138	
Targeted reliability Improvement, Dist - ID	364	ID	Various	1,138,995	
Replace Overhead Distribution Lines - Other - WY	364	WYP	Various	1,124,388	
Distribution Automation - Portland Ph 1	364	OR	Dec-20	1,092,851	
Oregon DIst- Sub - Swtchgr, Breakers, Reclos	364	OR	Various	1,050,128	
Replace - Storm & Casualty - ID	364	ID	Various	1,048,723	
Madras SC: Design & Build Grid Resilience Facility	364	OR	Dec-20	1,022,859	
Downtown SLC B LLC, New 1.91 MW Load	364	UT	Dec-20	1,014,086	
DJ to Thunder Creek Transmission Conversion Thunder Creek Xfmr	364	WYP	Sep-19	1,013,694	
Wash.-Replace-Storm and Casualty	364	WA	Various	1,005,054	
Idaho-New Connect - Commercial	364	ID	Various	1,001,071	
Projects Less Than $1million	364	CA	Various	7,698,622	
Projects Less Than $1million	364	ID	Various	6,448,121	
Projects Less Than $1million	364	OR	Various	12,188,366	
Projects Less Than $1million	364	UT	Various	13,768,917	
Projects Less Than $1million	364	WA	Various	6,545,706	
Projects Less Than $1million	364	WYP	Various	6,838,121	
Distribution Plant Five Year Average Removals	364	CA		(1,058,136)	
Distribution Plant Five Year Average Removals	364	ID		(1,435,230)	
Distribution Plant Five Year Average Removals	364	OR		(8,640,698)	
Distribution Plant Five Year Average Removals	364	UT		(12,128,365)	
Distribution Plant Five Year Average Removals	364	WA		(2,323,400)	
Distribution Plant Five Year Average Removals	364	WYP		(3,516,874)	
				563,750,019	

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions
General Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July19 to Dec20 Plant Adds	Ref.
AMI - Utah IT Comm Network	397	UT	Dec-20	22,915,307	
Open Floor Plan - OR - Structure OR	397	SO	Various	17,491,489	8.5.30
Replace Vehicles - UT	397	UT	Various	12,943,663	
CORE IT	397	SO	Various	10,489,599	
Oregon AMI - Distribution - Hardware	397	OR	Various	8,061,851	
General Plant	397	SO	Various	7,110,910	
Replace Vehicles - WY	397	WYP	Various	5,474,130	
PP Com Plant OR	397	OR	Various	4,771,763	
Oregon Replace Deteriorated Vehicles	397	OR	Various	3,909,187	
Replace Vehicles - ID	397	ID	Various	3,487,314	
PP Vehicles CA	397	CA	Various	3,068,104	
Structures Blankets - UT	397	UT	Various	2,659,431	
Hydro Gen/Other Equipment Failure Emergent 2020	397	SG	Various	1,909,771	
Oregon - Replace - Other General Plant	397	OR	Various	1,800,880	
PP Structures OR	397	OR	Various	1,656,220	
PP Hydro General Plant	397	SG	Various	1,621,095	
Replace Other General Plant - WY	397	WYP	Various	1,456,844	
Structures Blankets - ID	397	ID	Various	1,389,224	
Replace Other General Plant - UT	397	UT	Various	1,330,157	
Replace Tools - UT	397	UT	Various	1,301,551	
Calapooya to Fry Sub Fiber Install	397	SG	Dec-20	1,237,861	
PP Hydro Vehicles	397	SG	Various	1,019,130	
Projects Less Than $1million	397	CA	Various	1,519,180	
Projects Less Than $1million	397	SG	Various	14,671,496	
Projects Less Than $1million	397	ID	Various	2,837,767	
Projects Less Than $1million	397	OR	Various	4,555,402	
Projects Less Than $1million	397	SO	Various	5,775,355	
Projects Less Than $1million	397	UT	Various	3,919,028	
Projects Less Than $1million	397	WA	Various	2,971,059	
Projects Less Than $1million	397	WYP	Various	3,019,605	
General Plant Five Year Average Removals	397	SO		(1,396,061)	
				154,978,311	

PacifiCorp
Oregon General Rate Case - December 2021
Pro Forma Plant Additions
Intangible Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July19 to Dec20 Plant Adds	Ref.
CORE IT	303	SO	Various	11,727,662	
PP-IT	303	SO	Various	8,878,450	
WEST	303	SO	Dec-20	4,082,899	
IronNet	303	SO	Dec-20	2,041,450	
Mapping Sys Consolidation	302	SO	Jun-20	1,958,455	
Monarch upgrade	303	SO	Jun-20	1,659,004	
Replace PAR/SO - Integrated Resource Plan (IRP) software	303	SO	Jul-20	1,246,854	
UII Revenue Module	303	SO	Dec-20	1,224,870	
Landlord microsite	303	SO	Dec-20	1,224,870	
SMS check balance , pay bill	303	SO	Dec-20	1,143,212	
Projects Less Than $1million	303	OR	Various	-	
Projects Less Than $1million	303	SO	Various	3,981,115	
				39,168,841	

PacifiCorp
Oregon General Rate Case - December 2021
Plant Retirements
5 Year Average Retirement Amount

Function	Factor	Code	FY2015 (CY2014) Retirements	FY2016 (CY2015) Retirements	FY2017 (CY2016) Retirements	FY2018 (CY2017) Retirements	FY2019 (CY2018) Retirements	Large Items to Exclude	5 Year Avg	Monthly Amount
STMP	DGU	STMPDGU	(25,586,701)	(6,334,203)	(60,466,542)	(3,295,196)	(3,805,358)	57,266,637	(8,444,273)	(703,689)
STMP	DGP	STMPDGP	(4,593,021)	(7,552,129)	(11,698,034)	(5,214,803)	(4,346,678)	3,286,891	(6,023,555)	(501,963)
STMP	SSGCH	STMPSSGCH	(3,785,290)	(772,057)	(2,261,073)	(2,579,284)	(3,285,038)	-	(2,536,549)	(211,379)
STMP	SG	STMPSG	(33,649,156)	(70,369,377)	(122,676,137)	(37,870,150)	(41,678,721)	127,853,580	(35,677,992)	(2,973,166)
			(67,614,168)	(85,027,767)	(197,101,786)	(48,959,432)	(53,115,795)	188,407,108	(52,682,368)	(4,390,197)
HYDP	SG-U	HYDPSG-U	(41,566)	(750,627)	(69,704)	(208,532)	(669,210)	561,432	(235,641)	(19,637)
HYDP	SG-P	HYDPSG-P	(5,902,222)	(3,287,089)	(534,323)	(1,069,662)	(3,174,454)	1,065,452	(2,580,459)	(215,038)
HYDP	DGU	HYDPDGU	(132,774)	(181,308)	(35,672)	(187,001)	(523,331)	60,425	(199,932)	(16,661)
HYDP	DGP	HYDPDGP	(586,060)	(588,454)	(690,292)	(321,786)	(874,490)	-	(612,216)	(51,018)
HYDP	NUTIL	HYDPNUTIL	-	-	-	-	-	-	-	-
			(6,662,623)	(4,807,477)	(1,329,991)	(1,786,981)	(5,241,484)	1,687,309	(3,628,249)	(302,354)
OTHP	DGU	OTHPDGU	-	-	-	-	-	-	-	-
OTHP	SG	OTHPSG	(1,641,779)	(53,128,299)	(52,023,479)	(1,957,257)	(16,761,294)	11,677,207	(22,766,980)	(1,897,248)
OTHP	SG-W	OTHPSG-W	(7,130,774)	(5,751,491)	(6,963,155)	(4,776,936)	(82,725)	-	(4,941,016)	(411,751)
OTHP	SSGCT	OTHPSSGCT	(771,054)	(738,143)	(401,147)	(187,547)	(2,256,844)	-	(870,947)	(72,579)
OTHP	NUTIL	OTHPNUTIL	-	-	-	-	-	-	-	-
			(9,543,607)	(59,617,933)	(59,387,781)	(6,921,740)	(19,100,863)	11,677,207	(28,578,943)	(2,381,579)
TRNP	DGP	TRNPDGP	(2,502,894)	(2,784,751)	(1,393,287)	(2,977,569)	(1,293,599)	-	(2,190,420)	(182,535)
TRNP	DGU	TRNPDGU	(4,526,777)	(4,823,025)	(3,069,434)	(2,818,962)	(7,288,536)	-	(4,505,347)	(375,446)
TRNP	SG	TRNPSG	(14,089,309)	(10,790,943)	(8,479,048)	(9,180,945)	(7,082,678)	-	(9,924,584)	(827,049)
			(21,118,980)	(18,398,719)	(12,941,768)	(14,977,477)	(15,664,813)	-	(16,620,351)	(1,385,029)
DSTP	CA	DSTPCA	(1,375,217)	(854,573)	(767,723)	(691,930)	(4,729,076)	-	(1,683,704)	(140,309)
DSTP	ID	DSTPID	(2,457,201)	(1,827,434)	(1,625,059)	(1,736,718)	(2,203,340)	-	(1,969,951)	(164,163)
DSTP	MT	DSTPMT	-	-	-	-	-	-	-	-
DSTP	OR	DSTPOR	(8,874,251)	(7,781,832)	(7,879,266)	(9,930,730)	(42,097,594)	-	(15,312,734)	(1,276,061)
DSTP	UT	DSTPUT	(14,002,017)	(15,474,817)	(20,468,213)	(13,156,488)	(16,986,844)	-	(16,017,676)	(1,334,806)
DSTP	WA	DSTPWA	(1,961,589)	(1,634,310)	(1,866,808)	(1,797,818)	(2,504,228)	-	(1,952,950)	(162,746)
DSTP	WYP	DSTPWYP	(3,441,405)	(3,256,649)	(2,992,348)	(3,232,370)	(3,122,221)	-	(3,208,999)	(267,417)
DSTP	WYU	DSTPWYU	(229,238)	(213,993)	(374,558)	(241,028)	(296,106)	-	(270,985)	(22,582)
DSTP	NUTIL	DSTPNUTIL	-	-	-	-	-	-	-	-
			(32,340,918)	(31,043,608)	(35,973,974)	(30,787,082)	(71,939,410)	-	(40,416,998)	(3,368,083)
GNLP	SE	GNLPSE	(1,106)	218,341	(234,645)	(24,616)	(130,808)	-	(34,567)	(2,881)
GNLP	SSGCT	GNLPSSGCT	(795)	-	-	-	-	-	(159)	(13)
GNLP	SG	GNLPSG	(3,589,115)	(5,998,617)	(7,978,440)	(5,884,655)	(5,290,627)	-	(5,748,291)	(479,024)
GNLP	DGP	GNLPDGP	(175,417)	(18,917)	(354,539)	(246,476)	(10,091)	-	(161,088)	(13,424)
GNLP	DGU	GNLPDGU	(178,039)	(10,585)	(414,250)	(1,280)	(70,539)	-	(134,938)	(11,245)
GNLP	SO	GNLPSO	(17,421,663)	(14,531,433)	(13,123,182)	(12,981,865)	(12,881,251)	-	(14,187,879)	(1,182,323)
GNLP	CN	GNLPCN	(1,104,850)	(3,484,549)	(1,021,984)	(598,547)	(3,163,468)	-	(1,874,680)	(156,223)
GNLP	CA	GNLPCA	(154,520)	(143,515)	(107,582)	(99,292)	(715,495)	-	(244,081)	(20,340)
GNLP	ID	GNLPID	(372,813)	(606,266)	(740,915)	(310,512)	(1,368,673)	-	(679,836)	(56,653)
GNLP	SSGCH	GNLPSSGCH	(86,044)	(182,191)	(27,037)	(119,898)	(401,080)	-	(163,250)	(13,604)
GNLP	OR	GNLPOR	(3,807,301)	(4,362,381)	(4,306,824)	(2,634,074)	(5,945,198)	-	(4,211,156)	(350,930)
GNLP	UT	GNLPUT	(2,746,014)	(3,425,991)	(4,549,271)	(3,346,788)	(7,770,797)	-	(4,367,772)	(363,981)
GNLP	WA	GNLPWA	(1,251,786)	(533,674)	(1,613,793)	(856,950)	(1,132,533)	-	(1,077,747)	(89,812)
GNLP	WYU	GNLPWYU	(229,825)	(137,345)	(510,756)	(319,125)	(493,517)	-	(338,114)	(28,176)
GNLP	WYP	GNLPWYP	(1,655,600)	(886,638)	(5,754,744)	(1,903,007)	(3,446,458)	-	(2,729,289)	(227,441)
GNLP	NUTIL	GNLPNUTIL	-	-	-	-	-	-	-	-
			(32,774,887)	(34,103,761)	(40,737,962)	(29,327,084)	(42,820,534)	-	(35,952,846)	(2,996,070)
MNGP	SE	MNGPSE							-	-
MNGP	NUTIL	MNGPNUTIL							-	-
			-	-	-	-	-	-	-	-
INTP	DGP	INTPDGP	-	-	-	-	-	-	-	-
INTP	DGU	INTPDGU	-	-	-	-	-	-	-	-
INTP	SG-P	INTPSG-P	(800,979)	-	-	-	-	-	(160,196)	(13,350)
INTP	SG-U	INTPSG-U	-	-	-	-	-	-	-	-
INTP	SG	INTPSG	(86,720)	(17,832,488)	(677,401)	(220,378)	(1,546,900)	-	(4,072,777)	(339,398)
INTP	SO	INTPSO	(9,148,909)	(5,816,693)	(42,906,524)	(4,298,237)	(5,104,327)	-	(13,454,938)	(1,121,245)
INTP	CN	INTPCN	-	-	(50,673)	(1,982,186)	(10,680)	-	(408,708)	(34,059)
INTP	SE	INTPSE	-	(3,442,799)	(221,464)	(8,646)	(14,653)	-	(737,513)	(61,459)
INTP	CA	INTPCA	-	-	-	-	-	-	-	-
INTP	ID	INTPID	-	-	-	(5,175)	-	-	(1,035)	(86)
INTP	OR	INTPOR	(7,799)	-	-	-	(21,797)	-	(5,919)	(493)
INTP	UT	INTPUT	(54,895)	-	-	(28,178)	-	-	(16,614)	(1,385)
INTP	WA	INTPWA	-	-	-	-	-	-	-	-
INTP	WYU	INTPWYU	-	-	-	-	-	-	-	-
INTP	WYP	INTPWYP	(5,091)	(335,583)	(463,713)	-	-	-	(160,877)	(13,406)
			(10,104,392)	(27,427,563)	(44,319,775)	(6,542,800)	(6,698,358)	-	(19,018,578)	(1,584,881)
			(180,159,575)	(260,426,828)	(391,793,037)	(139,302,597)	(214,581,257)	201,771,624	(196,898,334)	(16,408,194)

PacifiCorp
Oregon General Rate Case – December 2021
Pro Forma Plant Addition Descriptions
Projects Greater Than $10 Million

OTHER PLANT ADDITIONS:

Pryor Mtn Wind Project 240 MW 2020 (Reference page 8.5.20 (in-service Dec-20)
WPRY/2018/C/001- 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 57 Vestas Model 110-2.0 MW safe harbor, 24 Vestas Model 110-2.2 MW safe harbor and 29 Vestas model 110-2.2 MW follow-on WTGs. In addition PacifiCorp will utilize four General Electric Model 116-2.3 MW safe harbor wind turbines. In addition to the wind turbines there will be a 34.5 kilovolt ("kV") collector systems; 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 planned in-service date for the project is December 2020.

Lake Side: STG20 GENERATOR Stator Replacement and Rotor Rewind (Reference page 8.5.20) (in-service Jan-20) OLSP/2019/C/014 – On August 18, 2019 the Lake Side steam turbine tripped following a generator stator fault. Examination and testing indicated that replacement of the stator and rewind of the rotor are required. The scope of the project includes dismantling the steam turbine generator, rewinding the rotor, replacing the stator, and reassembly.

Lake Side: U11 Combustion Overhaul-CY20 (Reference page 8.5.20) (in-service Apr-20)
Lake Side Unit 11 gas combustion turbine overhaul includes the replacement of combustion turbine parts and associated labor in accordance with the long term maintenance contract. The overhaul includes the replacement of program parts in the combustion and hot gas path sections of the gas turbine. The program parts are defined as transition seals, baskets, pilot nozzles, transitions, ring segments, blades and vanes. The service contract requires that the combustion turbine be maintained to the standards agreed upon per the maintenance contract and should occur after a specified number of factored fired hours or equivalent gas turbine starts.

Lake Side: U12 Combustion Overhaul-CY20 (Reference page 8.5.20) (in-service Apr-20)
Lake Side Unit 12 gas combustion turbine overhaul includes the replacement of combustion turbine parts and associated labor in accordance with the long term maintenance contract. The overhaul includes the replacement of program parts in the combustion and hot gas path sections of the gas turbine. The program parts are defined as transition seals, baskets, pilot nozzles, transitions, ring segments, blades and vanes. The service contract requires that the combustion turbine be maintained to the standards agreed upon per the maintenance contract and should occur after a specified number of factored fired hours or equivalent gas turbine starts.

TRANSMISSION PLANT ADDITIONS:

Vantage Pomona Heights 230kV Line (Reference 8.5.21) (in-service May-20)
The Vantage to Pomona Heights project consists of two sequences of work. The first sequence of work included the expansion of the Pomona Heights substation 230 kilovolt ring bus to provide adequate breaker separation between lines and transformers for breaker failure and bus fault events. This portion of the project was completed and placed in service in November 2015.

The second sequence of work includes installation of a new 230 kilovolt transmission line connected at the Bonneville Power Administration Vantage substation near Vantage, Washington, and ending at the PacifiCorp Pomona Heights substation in Yakima, Washington. The project will include the installation of breakers, protection and control equipment, and communications equipment at each substation as required to monitor and safely operate the new line. The infrastructure additions at the Vantage substation will be designed, purchased, installed, and maintained by Bonneville Power Administration. This sequence of work is estimated to be placed in service in May 2020.

This project corrects several existing North American Electric Reliability Corporation TPL deficiencies, eliminates the need to shed Yakima area load, eliminates overload of PacifiCorp and Bonneville Power Administration system with loss of the existing line, and meets the identified infrastructure needs in the joint area plan.

Goshen-Sugarmill-Rigby 161kV Transmission Line (Reference 8.5.21) (in-service Nov-20)
The Goshen-Sugarmill-Rigby 161 kilovolt Transmission Line project consists of two sequences of work. The first sequence rebuilds approximately 25 miles of existing 69 kilovolt line to 161 kilovolt from Goshen substation to Sugarmill substation located in the southeast Idaho area. Substation expansion and new line positions at Goshen and Sugarmill substation will be required. This sequence of work is estimated to be placed in service in November 2020.

The second sequence of work is to construct a new approximately 24 mile long 161 kilovolt line from Sugarmill to Rigby substation. This sequence of work is estimated to be placed in service in 2022 and is outside of the general rate case test period.

This overall project addresses overloading on the Goshen – Rigby and Goshen – Sugarmill lines in addition to low voltage at Rigby and Sugarmill substations that manifest under heavy loading conditions.

Goshen #3 345/161 kV 700 MVA Trfrmr Inst (Reference 8.5.21) (in-service Nov-20)
The Goshen #3 345/161 kilovolt 700 MVA Transformer Installation project consists of two sequences of work. The project will ultimately interconnect a third 345/161 kilovolt transformer at the Goshen substation located in southeast Idaho estimated to be placed in service in 2021. However, the existing Goshen 161 kilovolt bus is inadequate to reliably serve the peak load in the Goshen area and interconnect the third 700 MVA transformer, so the first sequence of the project is to expand the 161 kilovolt yard and convert the existing Goshen 161 kilovolt dual operate bus into a breaker and one-half scheme. Redundant 161 kilovolt relays will also be installed. This sequence of the project will be placed in service in November 2020.

This project corrects North American Electric Reliability Corporation TPL deficiencies for thermal overloading issues on the existing Goshen transformer beginning in 2021.

Wildfire Mitigation – Trans (Reference 8.5.21) (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.

Jordanelle - Midway Construct 138 kV Line – Trans (Reference 8.5.21) (in-service Nov-20)
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 PacifiCorp and, for portions, HLP will have circuits and other facilities attached to PacifiCorp 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.

Oregon New Large Load Network Upgrades (Reference page 8.5.21) (in-service Dec-20)
TZBE/2017/C/002/B
The Oregon New Large Load Network Upgrade is to serve a 60 MW Load Addition project which is to construct 230 kV system improvements necessary to provide service to new load near an existing Prineville Data Center. The customer intends to add an additional 220 MW of load between 2020 and 2022 that the proposed improvements will also be able to service.
The current property is served via the Prineville area 115 kV system out of Houston Lake substation. The current contract capacity is for 120 MW. When combining the contract capacity out of Houston Lake, another customer load of 57 MW of contract capacity out of Baldwin Road and Prineville area load of 44 MW, the current 115 kV system cannot accommodate the new data center load of 60 MW (or the additional 220 MW). Adding additional load to the current 115 kV system results in two N-1 NERC TPL thermal violations with thermal loading in excess of 124% and a number of N-1-1 scenarios resulting in NERC TPL thermal and voltage violations. Maintaining compliance with NERC TPL standards will require system modifications that will add capacity before the new load can be served.
The solution to serve the new 60 MW load, with the ability to also serve the next 220 MW load addition, is to (1) obtain a second 230 kV source from BPA at Ponderosa substation, (2) construct a 230 kV substation to support 230 kV interconnection of the BPA source lines to the new infrastructure, (3) construct two 230 kV transmission lines and (4) construct a 230 kV Point of Interconnect substation.

Q0542 Pryor Mountain – Trans (Reference 8.5.21) (in-service Dec-20)
The Q0542 Pryor Mountain project is to interconnect 240 megawatts of new wind generation to PacifiCorp's Frannie - Yellowtail 230 kilovolt transmission line approximately 14.2 miles north of the Frannie substation located in Carbon County, Montana. The network upgrades included in the scope of this project include: the installation of a new three-breaker ring bus substation; installation of approximately 55 miles of fiber optic cable from the Point of Interconnection substation to Frannie and Yellowtail substations; installation of communications equipment at various Transmission Provider locations; and a new transmission line loop in/out of the 230 kV Frannie-Yellowtail transmission line to the Point of Interconnection substation.

DISTRIBUTION PLANT ADDITIONS:

Wildfire Mitigation Plan - OR D (Reference page 8.5.22) (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.

PacifiCorp
Oregon General Rate Case – December 2021
Pro Forma Plant Addition Descriptions
Projects Greater Than $10 Million

GENERAL PLANT ADDITIONS:

Open Floor Plan - OR - Structure OR (Reference page 8.5.24) (in-service various)
The Open Floor Plan project encompasses the remodel of the Lloyd Center Tower in Portland, Oregon, to an open floor plan. Assets will include architectural services, construction of conference rooms and enclaves at the Lloyd Center Tower. The project will provide and install 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. This is a multi-year project that will begin with the 20th floor. The remaining floor remodels will be phased from 2020 through 2022.

PacifiCorp
Oregon General Rate Case - December 2021
Miscellaneous Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
1 - Fuel Stock - Pro Forma	151	3	(13,828,605)	SE	25.101%	(3,471,186)	8.6.1
1 - Fuel Stock - Working Capital Deposit	25316	3	415,538	SE	25.101%	104,306	8.6.1
1 - Fuel Stock - Working Capital Deposit	25317	3	(85,765)	SE	25.101%	(21,528)	8.6.1
2 - Prepaid Overhauls	186M	3	3,355,979	SG	26.023%	873,314	8.6.1

Description of Adjustment:

1 - Fuel stock levels for December 2021 are projected to be lower than June 2019 levels due to a decrease in the amount of coal stockpiled, offset slightly by higher stockpile unit costs. The adjustment also reflects the working capital deposits which are an offset to fuel stock costs.

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 2021.

PacifiCorp
Oregon General Rate Case - December 2021
Miscellaneous Rate Base
13 Month Average Balances - Summary

1 - Coal Fuel Stock Balances by Plant	Account	Factor	Jun-2019 EOP Balance	Dec-2021 13 Mth. Avg. Balance	Adj. to 13 Mth. Avg. Balance	
Jim Bridger	151	SE	26,712,955	27,844,659	1,131,704	
Cholla	151	SE	14,945,408	0	(14,945,408)	
Colstrip	151	SE	1,623,382	1,848,813	225,432	
Craig	151	SE	9,530,692	3,697,043	(5,833,649)	
Hayden	151	SE	1,689,816	2,367,854	678,038	
Hunter	151	SE	43,949,129	46,916,454	2,967,325	
Huntington	151	SE	29,455,022	25,876,891	(3,578,131)	
Dave Johnston	151	SE	9,748,141	11,533,795	1,785,654	
Naughton	151	SE	17,309,685	21,050,116	3,740,431	
Rock Garden	151	SE	31,430,017	31,430,017	-	
Total			186,394,247	172,565,641	**(13,828,605)**	**Ref. 8.6**

1 - Working Capital Deposits	Account	Factor	Jun-2019 EOP Balance	Dec-2021 13 Mth. Avg. Balance	Adj. to 13 Mth. Avg. Balance	
UAMPS Working Capital Deposit	25316	SE	(2,479,000)	(2,063,462)	**415,538**	**Ref. 8.6**
DPEC Working Capital Deposit	25317	SE	(2,622,091)	(2,707,856)	**(85,765)**	**Ref. 8.6**

2 - Overhaul Prepayments by Plant	Account	Factor	Jun-2019 EOP Balance	Dec-2021 13 Mth. Avg. Balance	Adj. to 13 Mth. Avg. Balance	
Lake Side 1	186M	SG	24,985,938	8,304,861	(16,681,077)	
Chehalis	186M	SG	13,780,118	20,702,217	6,922,099	
Currant Creek	186M	SG	12,587,709	15,991,492	3,403,784	
Lake Side 2	186M	SG	12,165,184	22,675,466	10,510,281	
Chehalis O&M	186M	SG	577,422	943,916	366,494	
Currant Creek O&M	186M	SG	1,169,213	3,611	(1,165,602)	
Total			65,265,584	68,621,563	**3,355,979**	**Ref. 8.6**

PacifiCorp
Oregon General Rate Case - December 2021
FERC 105 (PHFU) Adjustment

	ACCOUNT	TYPE	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove PHFU	105	1	(12,580,836)	SG	26.023%	(3,273,865)	
Remove PHFU	105	1	(683,318)	CA	Situs	-	
Remove PHFU	105	1	(7,426,112)	OR	Situs	(7,426,112)	
Remove PHFU	105	1	(5,730,529)	UT	Situs	-	
Remove PHFU	105	1	(601)	WYP	Situs	-	
			(26,421,395)			(10,699,976)	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 2021
FERC 105 (PHFU) Adjustment

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	2,902,972
1050000	Plant Held for Future Use	3502000	Land rights	SG	754,562
1050000	Plant Held for Future Use	3601000	Land owned in fee	OR	3,918,273
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	WYP	601
1050000	Plant Held for Future Use	3601000	Land owned in fee	UT	5,730,529
1050000	Plant Held for Future Use	3891000	Land owned in fee	OR	3,507,838
Total					**26,421,395**
					Ref. 8.7

PacifiCorp
Oregon General Rate Case - December 2021
Regulatory Assets & Liabilities Amortization

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenues:							
Wheeling Revenues	456	3	4,630,292	OR	Situs	4,630,292	8.8.4
Adjustment to Expense:							
Elec. Plant Acq. Amort. Exp.	406	3	-	SG	26.023%	-	8.8.1
Adjustment to Rate Base:							
Elec. Plant Gross Acq.	114	3	-	SG	26.023%	-	8.8.1
Elec. Plant Acq. Acc. Amort.	115	3	(9,563,119)	SG	26.023%	(2,488,575)	8.8.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMDT	3	4,630,292	OR	Situs	4,630,292	8.8.4
Deferred Income Tax Expense	41010	3	1,138,428	OR	Situs	1,138,428	8.8.4
Accumulated Def Inc Tax Balance	190	3	2,707,772	OR	Situs	2,707,772	8.8.4

Description of Adjustment:

This adjustment adds into results the proposed amortization of the remainder of the Post-2017 FERC OATT Revenue Deferral balance, net of the net book value of replaced wind equipment, as described in Docket UE-369, direct testimony of Mr. Steven R. McDougal (PAC/400, Page 9). The company proposes in this general rate case to begin amortizing the remainder of this balance over three years, beginning on the proposed effective date of January 1, 2021. This adjustment also walks forward Electric Plant Acquisition in the base period (12 months ended June 2019) to pro forma period levels (12 months ending December 2021).

PacifiCorp
Oregon General Rate Case - December 2021
Regulatory Assets & Liabilities Amortization
Electric Plant Acquisition Adjustment

Adjust Base Period to Pro Forma Period

		Rate Base	
	Amortization	**Gross Acq.**	**Acc Amort**
Pro Forma Amount (below)	4,781,559	144,704,699	(137,980,477)
Base Period Amount (below)	4,781,559	144,704,699	(128,417,358)
Pro Forma Adjustment	**-**	**-**	**(9,563,119)**
	Ref. 8.8	**Ref. 8.8**	**Ref. 8.8**

Year		Gross Acquisition	Beg Balance Accumlated Amortization	Amortization	End Balance Accumulated Amortization	13 Month Avg Bal Gross Acq	13 Month Avg Bal Acc Amort
	Opening Balance	144,704,699			(123,635,799)		
2018	July	144,704,699	(123,635,799)	(398,463)	(124,034,262)		
	August	144,704,699	(124,034,262)	(398,463)	(124,432,726)		
	September	144,704,699	(124,432,726)	(398,463)	(124,831,189)		
	October	144,704,699	(124,831,189)	(398,463)	(125,229,652)		
	November	144,704,699	(125,229,652)	(398,463)	(125,628,115)		
	December	144,704,699	(125,628,115)	(398,463)	(126,026,579)		
2019	January	144,704,699	(126,026,579)	(398,463)	(126,425,042)		
	February	144,704,699	(126,425,042)	(398,463)	(126,823,505)		
	March	144,704,699	(126,823,505)	(398,463)	(127,221,969)		
	April	144,704,699	(127,221,969)	(398,463)	(127,620,432)		
	May	144,704,699	(127,620,432)	(398,463)	(128,018,895)		
	June	144,704,699	(128,018,895)	(398,463)	(128,417,358)	144,704,699	(126,026,579)
			Base Period Amort =	(4,781,559)			
2019	July	144,704,699	(128,417,358)	(398,463)	(128,815,822)		
	August	144,704,699	(128,815,822)	(398,463)	(129,214,285)		
	September	144,704,699	(129,214,285)	(398,463)	(129,612,748)		
	October	144,704,699	(129,612,748)	(398,463)	(130,011,211)		
	November	144,704,699	(130,011,211)	(398,463)	(130,409,675)		
	December	144,704,699	(130,409,675)	(398,463)	(130,808,138)		
2020	January	144,704,699	(130,808,138)	(398,463)	(131,206,601)		
	February	144,704,699	(131,206,601)	(398,463)	(131,605,065)		
	March	144,704,699	(131,605,065)	(398,463)	(132,003,528)		
	April	144,704,699	(132,003,528)	(398,463)	(132,401,991)		
	May	144,704,699	(132,401,991)	(398,463)	(132,800,454)		
	June	144,704,699	(132,800,454)	(398,463)	(133,198,918)		
	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)	(135,589,697)		
2021	January	144,704,699	(135,589,697)	(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)		
	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)	(139,972,793)		
	December	144,704,699	(139,972,793)	(398,463)	(140,371,257)	144,704,699	(137,980,477)
			Pro Forma Amort =	(4,781,559)			

PacifiCorp
Oregon General Rate Case - December 2021
Regulatory Assets & Liabilities Amortization
Electric Plant Acquisition Adjustment
GL Account 140800 - Actuals for 12 Months Ended June 2019

Year	Month	Addition / Amortization	Accumulated Amount
2018	6	-	156,468,483
2018	7	-	156,468,483
2018	8	-	156,468,483
2018	9	-	156,468,483
2018	10	-	156,468,483
2018	11	-	156,468,483
2018	12	-	156,468,483
2019	1	-	156,468,483
2019	2	-	156,468,483
2019	3	-	156,468,483
2019	4	-	156,468,483
2019	5	-	156,468,483
2019	6	-	**156,468,483**

System-allocated amount	144,704,699	**Ref Tab B-15 & 8.8.1**
Utah-situs amount	11,763,784	**Ref Tab B-15**
	156,468,483	

GL Account Balance
Account Number 140800

Calendar year 2018

Period	Debit	Credit	Balance	Cumulative balance
Balance Carry...				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 2019

Period	Debit	Credit	Balance	Cumulative balance
Balance Carry				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 2021
Regulatory Assets & Liabilities Amortization
Accumulated Amortization
GL Account 145800 - Actuals for 12 Months Ended June 2019

Year	Month	Amort.	Accumulated Amount
2018	6	(423,600)	(124,628,434)
2018	7	(423,600)	(125,052,033)
2018	8	(423,600)	(125,475,633)
2018	9	(423,600)	(125,899,233)
2018	10	(423,600)	(126,322,832)
2018	11	(423,600)	(126,746,432)
2018	12	(423,600)	(127,170,031)
2019	1	(423,600)	(127,593,631)
2019	2	(423,600)	(128,017,231)
2019	3	(423,600)	(128,440,830)
2019	4	(423,600)	(128,864,430)
2019	5	(423,600)	(129,288,029)
2019	6	(423,600)	**(129,711,629)**

System-allocated amount	(128,417,358)	**Ref. Tab B-15 & 8.8.1**
Utah-situs amount	(1,294,270)	**Ref. Tab B-15**
	(129,711,629)	

GL Account Balance
Account Number 145800
Calendar year 2018

Period	Debit	Credit	Balance	Cumulative balance
Balance Carry...				122,086,836.46-
1		423,599.57	423,599.57-	122,510,436.03-
2		423,599.58	423,599.58-	122,934,035.61-
3		423,599.57	423,599.57-	123,357,635.18-
4		423,599.59	423,599.59-	123,781,234.77-
5		423,599.56	423,599.56-	124,204,834.33-
6		423,599.58	423,599.58-	124,628,433.91-
7		423,599.58	423,599.58-	125,052,033.49-
8		423,599.56	423,599.56-	125,475,633.05-
9		423,599.58	423,599.58-	125,899,232.63-
10		423,599.58	423,599.58-	126,322,832.21-
11		423,599.58	423,599.58-	126,746,431.79-
12		423,599.57	423,599.57	127,170,031.36

Calendar year 2019

Period	Debit	Credit	Balance	Cumulative balance
Balance Carry...				127,170,031.36-
1		423,599.57	423,599.57-	127,593,630.93-
2		423,599.58	423,599.58-	128,017,230.51-
3		423,599.57	423,599.57-	128,440,830.08-
4		423,599.59	423,599.59-	128,864,429.67-
5		423,599.56	423,599.56-	129,288,029.23-
6		423,599.58	423,599.58-	129,711,628.81-
7		423,599.58	423,599.58-	130,135,228.39-
8				130,135,228.39-
9				130,135,228.39-
10				130,135,228.39-
11				130,135,228.39-
12				130,135,228.39-

PacifiCorp
Oregon General Rate Case - December 2021
Regulatory Assets & Liabilities Amortization
FERC OATT Revenues Deferral (Post 2017)

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	(4,630,292)
Adjustment:	**4,630,292**
	Ref. 8.8

		Opening Bal.	Accrual[1]	Amortization	Interest[2,3]	Ending Bal.	
2019	June	(28,105,654)	(1,504,902)	-	(183,273)	(29,793,829)	**Ref 8.8.5**
	July	(29,793,829)	(879,882)	-	(192,010)	(30,865,721)	
	August	(30,865,721)	(1,164,318)	-	(199,720)	(32,229,759)	
	September	(32,229,759)	(1,023,270)	-	(207,935)	(33,460,964)	
	October	(33,460,964)	(752,593)	-	(214,895)	(34,428,452)	
	November	(34,428,452)	(671,937)	-	(220,783)	(35,321,172)	
	December	(35,321,172)	(223,901)	-	(225,030)	(35,770,104)	
2020	January	(35,770,104)	(600,867)	-	(229,078)	(36,600,048)	
	February	(36,600,048)	(608,459)	-	(234,373)	(37,442,880)	
	March	(37,442,880)	(714,036)	-	(240,061)	(38,396,978)	
	April	(38,396,978)	(617,616)	-	(245,814)	(39,260,408)	
	May	(39,260,408)	(883,343)	-	(252,141)	(40,395,892)	
	June	(40,395,892)	(1,300,443)	-	(260,677)	(41,957,012)	
	July	(41,957,012)	(1,552,276)	-	(271,391)	(43,780,680)	
	August	(43,780,680)	(1,491,452)	-	(282,780)	(45,554,911)	
	September	(45,554,911)	(971,477)	-	(292,396)	(46,818,784)	
	October	(46,818,784)	(522,576)	-	(298,998)	(47,640,358)	
	November	(47,640,358)	(704,698)	-	(304,794)	(48,649,849)	
	December	(48,649,849)	(768,167)	-	(311,406)	(49,729,423)	

SCHMDT	41010	ADIT -190
-	-	3,276,986

Balance of Wind Faciliaties Replaced by Repowering - 2020 RAC	33,687,137 [4]
Foote Creeke Facilities Replaced by Repowering	2,713,942
Net Balance for Amortization	(13,328,343)

		Opening Bal.	Accrual[1]	Amortization	Interest[2,3]	Ending Bal.	SCHMDT	41010	ADIT -190
	December								
2021	January	(13,328,343)	-	(385,858)	(29,634)	(12,972,120)	(385,858)	94,869	3,182,117
	February	(12,972,120)	-	(385,858)	(28,853)	(12,615,116)	(385,858)	94,869	3,087,248
	March	(12,615,116)	-	(385,858)	(28,071)	(12,257,329)	(385,858)	94,869	2,992,379
	April	(12,257,329)	-	(385,858)	(27,287)	(11,898,758)	(385,858)	94,869	2,897,510
	May	(11,898,758)	-	(385,858)	(26,501)	(11,539,401)	(385,858)	94,869	2,802,641
	June	(11,539,401)	-	(385,858)	(25,713)	(11,179,257)	(385,858)	94,869	2,707,772
	July	(11,179,257)	-	(385,858)	(24,924)	(10,818,324)	(385,858)	94,869	2,612,903
	August	(10,818,324)	-	(385,858)	(24,133)	(10,456,599)	(385,858)	94,869	2,518,034
	September	(10,456,599)	-	(385,858)	(23,340)	(10,094,081)	(385,858)	94,869	2,423,165
	October	(10,094,081)	-	(385,858)	(22,546)	(9,730,770)	(385,858)	94,869	2,328,296
	November	(9,730,770)	-	(385,858)	(21,749)	(9,366,661)	(385,858)	94,869	2,233,427
	December	(9,366,661)	-	(385,858)	(20,951)	(9,001,755)	(385,858)	94,869	2,138,558
			Pro Forma Amort =	(4,630,292)			**(4,630,292)**	**1,138,428**	**2,707,772**
							Ref 8.8	**Ref 8.8**	**Ref 8.8**

Note:
1. 2020 accrual amounts based on Docket UM 1639(7), Confidential Exhibit C, filed December 27, 2019.
2. Interest rate in deferral period per approved WACC from UE-264.
3. Interest rate in amortization period per UM-1147, MBT Rate, approved January 17, 2020.
4. Please refer to the Direct Testimony of Mr. Steven R. McDougal (PAC/400, Page 9) in Docket UE-369.

PacifiCorp
Oregon General Rate Case - December 2021
Regulatory Assets & Liabilities Amortization
FERC OATT Revenues Deferral (Post 2017)
GL Account 288232 - Actuals for 12 Months Ended June 2019

Year	Month	Accrual	Interest	Accumulated Amount
2018	6	(774,717)	(105,092)	(17,040,278)
2018	7	(1,662,777)	(113,500)	(18,816,555)
2018	8	(1,483,478)	(124,211)	(20,424,244)
2018	9	(882,167)	(132,512)	(21,438,923)
2018	10	(605,308)	(138,077)	(22,182,309)
2018	11	(522,017)	(143,716)	(22,848,041)
2018	12	(421,397)	(146,442)	(23,415,881)
2019	1	(808,836)	(152,069)	(24,376,786)
2019	2	(1,148,469)	(158,460)	(25,683,715)
2019	3	(720,115)	(165,400)	(26,569,230)
2019	4	(646,658)	(170,790)	(27,386,678)
2019	5	(543,323)	(175,654)	(28,105,654)
2019	6	(1,504,902)	(183,273)	**(29,793,829)**
				Ref 8.8.4

GL Account Balance
Account Number 288232
Calendar year 2018

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				11,076,729.13-
1		436,634.56	436,634.56-	11,513,363.69-
2		616,725.55	616,725.55-	12,130,089.24-
3		967,969.41	967,969.41-	13,098,058.65-
4		487,864.38	487,864.38-	13,585,923.03-
5		2,574,545.76	2,574,545.76-	16,160,468.79-
6		879,809.64	879,809.64-	17,040,278.43-
7		1,776,276.50	1,776,276.50-	18,816,554.93-
8		1,607,689.23	1,607,689.23-	20,424,244.16-
9		1,014,679.13	1,014,679.13-	21,438,923.29-
10		743,385.49	743,385.49-	22,182,308.78-
11		665,732.69	665,732.69-	22,848,041.47-
12		567,839.42	567,839.42-	23,415,880.89-

Calendar year 2019

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				23,415,880.89-
1		960,905.26	960,905.26-	24,376,786.15-
2	1,115,141.87	2,422,070.62	1,306,928.75-	25,683,714.90-
3		885,514.70	885,514.70-	26,569,229.60-
4		817,447.92	817,447.92-	27,386,677.52-
5	422,941.51	1,141,917.66	718,976.15-	28,105,653.67-
6		1,688,175.16	1,688,175.16-	29,793,828.83-
7		1,071,892.07	1,071,892.07-	30,865,720.90-
8		1,364,038.41	1,364,038.41-	32,229,759.31-
9		1,231,205.11	1,231,205.11-	33,460,964.42-
10		967,487.92	967,487.92-	34,428,452.34-
11		892,719.97	892,719.97-	35,321,172.31-
12		448,931.30	448,931.30-	35,770,103.61-

PacifiCorp
Oregon General Rate Case - December 2021
Remove Rolling Hills

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Plant	341	1	(3,478,252)	SG	26.023%	(905,133)	
Other Plant	343	1	(179,652,601)	SG	26.023%	(46,750,336)	
Other Plant	344	1	(5,850,373)	SG	26.023%	(1,522,421)	
Other Plant	345	1	(12,324,482)	SG	26.023%	(3,207,155)	
Other Plant	346	1	(659,497)	SG	26.023%	(171,618)	
			(201,965,205)			(52,556,663)	8.9.1
Adjustment to Depreciation Reserve:							
Other Plant	108OP	1	70,468,924	SG	26.023%	18,337,869	8.9.1
Adjustment to O&M Expense:							
Administrative & General	929	1	(1,240,365)	SO	27.215%	(337,569)	8.9.1
Misc. Oth. Power Supply	549	1	(387)	SG	26.023%	(101)	8.9.1
Misc. Oth. Power Supply	553	1	(298,253)	SG	26.023%	(77,613)	8.9.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	1	(6,674,158)	SCHMDEXP	26.726%	(1,783,725)	
Schedule M Adjustment	SCHMDT	1	(29,347,530)	TAXDEPR	26.274%	(7,710,650)	
Schedule M Adjustment	SCHMDT	1	(27,588)	GPS	27.215%	(7,508)	
Deferred Tax Expense	41110	1	1,640,949	SCHMDEXP	26.726%	438,557	
Deferred Tax Expense	41010	1	(7,215,560)	TAXDEPR	26.274%	(1,895,787)	
Deferred Tax Expense	41010	1	(6,783)	GPS	27.215%	(1,846)	
Deferred Tax Expense - Flowthrough	41110	1	12,204	OR	Situs	12,204	
Accumulated Def Inc Tax Balance	282	1	11,746,394	OR	Situs	11,746,394	

This adjustment removes the gross plant, accumulated depreciation and O&M amounts related to the Rolling Hills wind resource from the 12 months ended June 2019. 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 Case - December 2021
Remove Rolling Hills

Rate Base Amounts	FERC Account	June 2019 End of Period	Ref.
Capital			
Other Plant	341	3,478,252	
Other Plant	343	179,652,601	
Other Plant	344	5,850,373	
Other Plant	345	12,324,482	
Other Plant	346	659,497	
		201,965,205	8.9
Depreciation Reserve			
Other Plant	108OP	(70,468,924)	8.9

Expense Amounts	FERC Account	12 ME June 2019	Ref.
Operation & Maintenance Expense			
Administrative & General	929	1,240,365	8.9
Misc. Oth. Power Supply	549	387	8.9
Misc. Oth. Power Supply	553	298,253	8.9

PacifiCorp
Oregon General Rate Case - December 2021
Carbon Plant Closure

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove system alloc deferral	403SP	1	(5,561,123)	SG	26.023%	(1,447,151)	8.10.1
Excess closing costs amort.	407	3	(1,795,238)	OR	Situs	(1,795,238)	8.10.2
Adjustment to Rate Base:							
Excess closing cost reserves	254	3	(8,078,569)	OR	Situs	(8,078,569)	8.10.2
Adjustment to Tax:							
Schedule M Adjustment	SCHMDT	3	1,795,238	OR	Situs	1,795,238	8.10.2
Deferred Income Tax Expense	41010	3	441,384	OR	Situs	441,384	8.10.2
Accumulated Def Inc Tax Balance	190	3	1,986,247	OR	Situs	1,986,247	8.10.2

Description of Adjustment:

The Carbon Plant was retired April, 2015 and will be fully recovered as of December 2020. This adjustment removes the allocation in the base period of accelerated depreciation deferral and amortization. This adjustment also 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.

PacifiCorp
Oregon General Rate Case - December 2021
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.

Deferral of Depreciation Expense - 12 Months Ended June 2019

Year	Posting period	Account Number	Amount	Text	FERC Account	FERC Location	Booked Allocation
2018	7	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2018	7	565131	44,602	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2018	7	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2018	7	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2018	8	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2018	8	565131	44,602	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2018	8	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2018	8	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2018	9	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2018	9	565131	44,602	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2018	9	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2018	9	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2018	10	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2018	10	565131	44,602	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2018	10	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2018	10	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2018	11	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2018	11	565131	44,602	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2018	11	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2018	11	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2018	12	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2018	12	565131	44,602	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2018	12	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2018	12	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2019	1	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2019	1	565131	44,602	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2019	1	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2019	1	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2019	2	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2019	2	565131	44,602	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2019	2	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2019	2	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2019	3	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2019	3	565131	44,602	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2019	3	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2019	3	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2019	4	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2019	4	565131	44,602	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2019	4	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2019	4	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2019	5	565131	(45,449)	Write-off Carbon removal for Cal. & Wash.	4032000	250	SG
2019	5	565131	(10,121)	Write-off Carbon removal for Cal. & Wash.	4032000	250	SG
2019	5	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2019	5	565131	44,602	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2019	5	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2019	5	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2019	6	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2019	6	565131	44,602	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2019	6	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2019	6	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
			5,561,123	**Ref 8.10**			

PacifiCorp
Oregon General Rate Case - December 2021
Carbon Plant Closure
Closing Costs in Pro Forma Period

The Company continues to carry an accumulated depreciation reserve for Carbon Plant decommissioning that has yet to be returned to Oregon customers. The Company is proposing a five-year amortization period, as per the 2018 Depreciation Study, to return the benefit of this rate base credit to ratepayers in Oregon.

Date	Beg Bal	Amortization	End Bal		Tax Impacts: SCHMDT	41010	ADIT - 190	ADIT 13MA Bal.	SCHMDT	41010
Dec-20			(8,976,188)				2,206,939			
Jan-21	(8,976,188)	149,603	(8,826,585)		149,603	36,782	2,170,157			
Feb-21	(8,826,585)	149,603	(8,676,982)		149,603	36,782	2,133,375			
Mar-21	(8,676,982)	149,603	(8,527,379)		149,603	36,782	2,096,593			
Apr-21	(8,527,379)	149,603	(8,377,776)		149,603	36,782	2,059,811			
May-21	(8,377,776)	149,603	(8,228,173)		149,603	36,782	2,023,029			
Jun-21	(8,228,173)	149,603	(8,078,569)		149,603	36,782	1,986,247			
Jul-21	(8,078,569)	149,603	(7,928,966)		149,603	36,782	1,949,465			
Aug-21	(7,928,966)	149,603	(7,779,363)		149,603	36,782	1,912,683			
Sep-21	(7,779,363)	149,603	(7,629,760)		149,603	36,782	1,875,901			
Oct-21	(7,629,760)	149,603	(7,480,157)		149,603	36,782	1,839,119			
Nov-21	(7,480,157)	149,603	(7,330,554)	**13MA Bal.**	149,603	36,782	1,802,337			
Dec-21	(7,330,554)	149,603	(7,180,951)	**(8,078,569)**	149,603	36,782	1,765,555	**1,986,247**	**1,795,238**	**441,384**
Amort exp. 12 months ending Dec. 2021		**1,795,238**		**Ref. 8.10**				**Ref. 8.10**	**Ref. 8.10**	**Ref. 8.10**

PacifiCorp
Oregon General Rate Case - December 2021
Pension and Other Postretirement Plan Balances Removal

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Net Prepaid Balance	128	1	(2,485,363)	SO	27.215%	(676,399)	8.11.1
Net Prepaid Balance	182M	1	(434,809,482)	SO	27.215%	(118,334,759)	8.11.1
Net Prepaid Balance	2283	1	98,349,221	SO	27.215%	26,766,048	8.11.1
			(338,945,624)			(92,245,110)	
Adjustment to Tax:							
ADIT Balances	190	1	(7,560,157)	SO	27.215%	(2,057,520)	8.11.2
ADIT Balances	283	1	97,593,593	SO	27.215%	26,560,401	8.11.2
			90,033,436			24,502,881	

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 2021
Pension and Other Postretirement Plan Balances Removal

Pension & Postretirement

FERC Account	Factor	June 2019 End of Period Balances	Ref
128	SO	2,485,363	**8.11**
182M	SO	434,809,482	**8.11**
2283	SO	(98,349,221)	**8.11**
		338,945,624	**8.11**

PacifiCorp
Oregon General Rate Case - December 2021
Pension and Other Postretirement Plan Balances Removal
Tax Adjustment Support

FERC Acct	SAP Account Description	SAP Acct	Forecast Period Per Tax Model	Test Period	Adjustment
190	DTA 720.800 FAS 158 Pension Liability	287460	9,398,642	-	(9,398,642)
190	DTA 720.810 FAS 158 Post-Retirement Liability	287461	(1,838,485)	-	1,838,485
283	DTL 720.815 Post-Retirement Asset	286909	(4,700,266)	-	4,700,266
283	DTL 320.270 Reg Asset - FAS 158 Pension	287738	(96,274,925)	-	96,274,925
283	DTL 320.280 Reg Asset - FAS 158 Post-Retirement	287739	3,381,598	-	(3,381,598)
			(90,033,436)	-	90,033,436

	Adjustment	
190/SO	(7,560,157)	**Ref. 8.11**
283/SO	97,593,593	**Ref. 8.11**
	90,033,436	

PacifiCorp
Oregon General Rate Case - December 2021
Deer Creek Mine Closure

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove base period expense							
Unrecovered Plant amortization	501	1	(8,319,574)	SE	25.101%	(2,088,337)	8.12.1
Unrec. Plant amortization - OR	501	1	(1,881,937)	OR	Situs	(1,881,937)	8.12.1
Closure cost amortization - WY	506	1	(3,233,528)	SG	26.023%	(841,449)	8.12.1
Add pro forma expense							
Closure Cost amortization	506	3	20,330,668	SE	25.101%	5,103,300	8.12.2
Prepaid Royalties amortization	506	3	4,039,412	SE	25.101%	1,013,953	8.12.5
Post-Retire. Settlement Loss amort.	926	3	2,774,358	SO	27.215%	755,050	8.12.3
Post-Retire. Settlement Benefits amort.	926	3	(3,681,646)	OR	Situs	(3,681,646)	8.12.4
Adjustment to Rate Base:							
Remove base period regulatory assets							
Closure Costs	182M	1	(60,534,393)	SE	25.101%	(15,195,033)	8.12.2
Unrecovered Plant	182M	1	(2,436,501)	SE	25.101%	(611,598)	B-16
Unrecovered Plant	182M	1	3,467,455	OR	Situs	3,467,455	B-16
Post-Retire. Settlement Loss	182M	1	(8,323,073)	SO	27.215%	(2,265,150)	8.12.3
Post-Retire. Settlement Savings	182M	1	8,283,704	OR	Situs	8,283,704	8.12.4
Add pro forma regulatory assets							
Closure Costs	182M	3	50,826,671	SE	25.101%	12,758,251	8.12.2
Post-Retire. Settlement Loss	182M	3	6,935,894	SO	27.215%	1,887,625	8.12.3
Post-Retire. Settlement Savings	182M	3	(9,204,116)	OR	Situs	(9,204,116)	8.12.4
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	4,039,412	SE	25.101%	1,013,953	8.12.6
Schedule M Adjustment	SCHMAT	3	2,774,358	SO	27.215%	755,050	8.12.6
Schedule M Adjustment	SCHMDT	3	69,638,487	SE	25.101%	17,480,296	8.12.6
Schedule M Adjustment	SCHMDT	3	(6,964,697)	OR	Situs	(6,964,697)	8.12.6
Deferred Income Tax Expense	41110	3	(993,154)	SE	25.101%	(249,296)	8.12.6
Deferred Income Tax Expense	41110	3	(682,120)	SO	27.215%	(185,641)	8.12.6
Deferred Income Tax Expense	41010	3	17,121,736	SE	25.101%	4,297,811	8.12.6
Deferred Income Tax Expense	41010	3	(1,712,382)	OR	Situs	(1,712,382)	8.12.6
Accumulated Def Inc Tax Balance	283	3	23,852,621	SE	25.101%	5,987,363	8.12.6
Accumulated Def Inc Tax Balance	190	3	(28,303,872)	SE	25.101%	(7,104,693)	8.12.6
Accumulated Def Inc Tax Balance	283	3	(492,377)	SO	27.215%	(134,002)	8.12.6
Accumulated Def Inc Tax Balance	283	3	957,698	OR	Situs	957,698	8.12.6

Description of Adjustment:

Oregon Order No. 15-161 in Docket UM 1712 addressed 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 have been recovered through a separate tariff riders.

Order No. 15-161 authorized a creation of a deferred account to track the Deer Creek Mine closure costs and costs due to Retiree Medical Obligation Settlement Loss to be addressed in the current ratemaking proceedings. The Company is proposing to include all deferred costs and savings in the rate base to be amortized over three years.

PacifiCorp
Oregon General Rate Case - December 2021
Deer Creek Mine Closure
Treatment of Deer Creek Unrecovered Plant

Deer Creek unrecovered plant was fully amortized over four years in May 2019 as ordered in Docket No. UM 1712, therefore, Deer Creek Unrecovered Plant amortization amounts should be removed from unadjusted results.

	Amort	FERC Account	Allocator	Ref
Amortization of unrecovered plant	**8,319,574**	**501**	**SE**	**8.12**
Oregon Portion of Amort and Recovery	**1,881,937**	**501**	**OR**	**8.12**

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.

	Amort	FERC Account	Allocator	Ref
Wyoming closure cost amortization in unadj. results	**3,233,528**	**506**	**SG**	**8.12**

PacifiCorp
Oregon General Rate Case - December 2021
Deer Creek Mine Closure
Closing Costs in Pro Forma Period

In UM 1712 the commission authorized a creation of a deferred account to track Deer Creek Mine closure costs.
In the current rate case, the Company is proposing a 3-year amortization schedule to recover mine closure costs.
The amounts below have been reduced for the joint owner portion.

Date	Beg Bal	Deferral	End Bal	
			60,534,393	**Ref. 8.12**
Jul-19	60,534,393	172,715	60,707,108	
Aug-19	60,707,108	(62,902)	60,644,206	
Sep-19	60,644,206	48,447	60,692,653	
Oct-19	60,692,653	43,653	60,736,307	
Nov-19	60,736,307	43,735	60,780,041	
Dec-19	60,780,041	20,466	60,800,507	
Jan-20	60,800,507	7,969	60,808,476	
Feb-20	60,808,476	7,969	60,816,445	
Mar-20	60,816,445	31,937	60,848,381	
Apr-20	60,848,381	31,937	60,880,318	
May-20	60,880,318	7,969	60,888,287	
Jun-20	60,888,287	31,937	60,920,224	
Jul-20	60,920,224	31,937	60,952,161	
Aug-20	60,952,161	7,969	60,960,129	
Sep-20	60,960,129	7,969	60,968,098	
Oct-20	60,968,098	7,969	60,976,067	
Nov-20	60,976,067	7,969	60,984,036	
Dec-20	60,984,036	7,969	60,992,005	

Date	Beg Bal	Amortization	End Bal	
Jan-21	60,992,005	(1,694,222)	59,297,782	
Feb-21	59,297,782	(1,694,222)	57,603,560	
Mar-21	57,603,560	(1,694,222)	55,909,338	
Apr-21	55,909,338	(1,694,222)	54,215,115	
May-21	54,215,115	(1,694,222)	52,520,893	
Jun-21	52,520,893	(1,694,222)	50,826,671	
Jul-21	50,826,671	(1,694,222)	49,132,448	
Aug-21	49,132,448	(1,694,222)	47,438,226	
Sep-21	47,438,226	(1,694,222)	45,744,004	
Oct-21	45,744,004	(1,694,222)	44,049,781	
Nov-21	44,049,781	(1,694,222)	42,355,559	**13MA Bal.**
Dec-21	42,355,559	(1,694,222)	40,661,337	**50,826,671**
Amort exp. 12 months ending Dec. 2021		**(20,330,668)**		**Ref. 8.12**
		Ref. 8.12		

PacifiCorp
Oregon General Rate Case - December 2021
Deer Creek Mine Closure
Retiree Medical Obligation Settlement Loss

	Beg Balance	Amortization	End Balance	
Jun-19	8,323,073		**8,323,073**	**Ref. 8.12**
Jul-19	8,323,073		8,323,073	
Aug-19	8,323,073		8,323,073	
Sep-19	8,323,073		8,323,073	
Oct-19	8,323,073		8,323,073	
Nov-19	8,323,073		8,323,073	
Dec-19	8,323,073		8,323,073	
Jan-20	8,323,073		8,323,073	
Feb-20	8,323,073		8,323,073	
Mar-20	8,323,073		8,323,073	
Apr-20	8,323,073		8,323,073	
May-20	8,323,073		8,323,073	
Jun-20	8,323,073		8,323,073	
Jul-20	8,323,073		8,323,073	
Aug-20	8,323,073		8,323,073	
Sep-20	8,323,073		8,323,073	
Oct-20	8,323,073		8,323,073	
Nov-20	8,323,073		8,323,073	
Dec-20	8,323,073		8,323,073	
Jan-21	8,323,073	(231,196)	8,091,877	
Feb-21	8,091,877	(231,196)	7,860,680	
Mar-21	7,860,680	(231,196)	7,629,484	
Apr-21	7,629,484	(231,196)	7,398,287	
May-21	7,398,287	(231,196)	7,167,091	
Jun-21	7,167,091	(231,196)	6,935,894	
Jul-21	6,935,894	(231,196)	6,704,698	
Aug-21	6,704,698	(231,196)	6,473,501	
Sep-21	6,473,501	(231,196)	6,242,305	
Oct-21	6,242,305	(231,196)	6,011,108	
Nov-21	6,011,108	(231,196)	5,779,912	**13MA Bal.**
Dec-21	5,779,912	(231,196)	5,548,715	**6,935,894**
Amort exp. 12 months ending Dec. 2021		**(2,774,358)**		**Ref. 8.12**
		Ref. 8.12		

PacifiCorp
Oregon General Rate Case - December 2021
Deer Creek Mine Closure
Savings Resulting from the UMWA PBOP Settlement

The UMWA PBOP settlement resulted in lower PBOP expense for the Company.
The Oregon portion of these savings were ordered to be deferred until the current Oregon General Rate Case.
The Company is proposing to return the savings that resulted from The UMWA PBOP settlement to customers over three year amortization period.

Date	Beg Bal	Deferral	End Bal	
Jun-19	(8,130,302)	(153,402)	**(8,283,704)**	**Ref. 8.12**
Jul-19	(8,283,704)	(153,402)	(8,437,106)	
Aug-19	(8,437,106)	(153,402)	(8,590,508)	
Sep-19	(8,590,508)	(153,402)	(8,743,910)	
Oct-19	(8,743,910)	(153,402)	(8,897,312)	
Nov-19	(8,897,312)	(153,402)	(9,050,714)	
Dec-19	(9,050,714)	(153,402)	(9,204,116)	
Jan-20	(9,204,116)	(153,402)	(9,357,518)	
Feb-20	(9,357,518)	(153,402)	(9,510,920)	
Mar-20	(9,510,920)	(153,402)	(9,664,322)	
Apr-20	(9,664,322)	(153,402)	(9,817,724)	
May-20	(9,817,724)	(153,402)	(9,971,125)	
Jun-20	(9,971,125)	(153,402)	(10,124,527)	
Jul-20	(10,124,527)	(153,402)	(10,277,929)	
Aug-20	(10,277,929)	(153,402)	(10,431,331)	
Sep-20	(10,431,331)	(153,402)	(10,584,733)	
Oct-20	(10,584,733)	(153,402)	(10,738,135)	
Nov-20	(10,738,135)	(153,402)	(10,891,537)	
Dec-20	(10,891,537)	(153,402)	(11,044,939)	

Date	Beg Bal	Amortization	End Bal	
			(11,044,939)	
Jan-21	(11,044,939)	306,804	(10,738,135)	
Feb-21	(10,738,135)	306,804	(10,431,331)	
Mar-21	(10,431,331)	306,804	(10,124,527)	
Apr-21	(10,124,527)	306,804	(9,817,724)	
May-21	(9,817,724)	306,804	(9,510,920)	
Jun-21	(9,510,920)	306,804	(9,204,116)	
Jul-21	(9,204,116)	306,804	(8,897,312)	
Aug-21	(8,897,312)	306,804	(8,590,508)	
Sep-21	(8,590,508)	306,804	(8,283,704)	
Oct-21	(8,283,704)	306,804	(7,976,900)	
Nov-21	(7,976,900)	306,804	(7,670,096)	**13MA Bal.**
Dec-21	(7,670,096)	306,804	(7,363,293)	**(9,204,116)**
Amort exp. 12 months ending Dec. 2021		**3,681,646**		**Ref. 8.12**
		Ref. 8.12		

PacifiCorp
Oregon General Rate Case - December 2021
Deer Creek Mine Closure
Recovery Royalties - Closure Costs

Recovery royalties, which are part of the Deer Creek mine closure costs, have been estimated but not spent. The Company is proposing three year amortization of these costs starting January 2021. The balance of the recovery royalties will not be included as part of the closure cost regulatory asset since the Company will not incur these expenses until the Deer Creek mine closure costs are fully paid.

Estimated Recovery Royalties $ 12,118,236

Date	Beg Bal	Amortization	End Bal
Dec-20			12,118,236
Jan-21	12,118,236	(336,618)	11,781,618
Feb-21	11,781,618	(336,618)	11,445,001
Mar-21	11,445,001	(336,618)	11,108,383
Apr-21	11,108,383	(336,618)	10,771,765
May-21	10,771,765	(336,618)	10,435,148
Jun-21	10,435,148	(336,618)	10,098,530
Jul-21	10,098,530	(336,618)	9,761,912
Aug-21	9,761,912	(336,618)	9,425,295
Sep-21	9,425,295	(336,618)	9,088,677
Oct-21	9,088,677	(336,618)	8,752,059
Nov-21	8,752,059	(336,618)	8,415,442
Dec-21	8,415,442	(336,618)	8,078,824
Amort exp. 12 months ending Dec. 2021		**(4,039,412)**	
		Ref. 8.12	

PacifiCorp
Oregon General Rate Case - December 2021
Deer Creek Mine Closure
Tax Support

Account			Allocation Factors	Forecast 2021 Per Tax Model	Forecast 13 MA Per 8.12	Adjustment to reflect 2021 Bal	
283	320.281	DTL 320.281 RA Post-Ret Settlement Loss (287848)	SO	(1,212,924)	(1,705,301)	(492,377)	**Ref. 8.12**
283	415.410	DTL 415.410 RA Energy West Mining (287840)	SE	(65,410,533)	(12,496,550)	52,913,983	**Ref. 8.12**
283	415.413	DTL 415.413 Cntra RA Deer Creek Aband - OR (287843)	OR	1,305,282	2,262,979	957,698	**Ref. 8.12**
283	415.424	DTL 415.424 Contra RA - Deer Creek Abandonment (287849)	SE	26,578,476		(26,578,476)	**Ref. 8.12**
190	720.560	DTA 720.560 Pension (287220)	SE	28,303,872		(28,303,872)	**Ref. 8.12**
283	- - - - - -	Royalties Recovery	SE	-	(2,482,885)	(2,482,885)	
		Total ADIT		(10,435,827)	(14,421,757)	**(3,985,930)**	
SCHMAT	320.281	DTL 320.281 RA Post-Ret Settlement Loss (287848)	SO	-	2,774,358	2,774,358	**Ref. 8.12**
SCHMDT	415.410	DTL 415.410 RA Energy West Mining	SE	89,969,155	20,330,668	(69,638,487)	**Ref. 8.12**
SCHMDT	415.413	DTL 415.413 Cntra RA Deer Creek Aband - OR (287843)	OR	(10,646,343)	(3,681,646)	6,964,697	**Ref. 8.12**
SCHMAT	- - - - - -	Royalties Recovery	SE	-	4,039,412	4,039,412	**Ref. 8.12**
		Total Schedule M		79,322,812	23,462,792	**(55,860,020)**	
41110	320.281	DTL 320.281 RA Post-Ret Settlement Loss (287848)	SO	-	(682,120)	(682,120)	**Ref. 8.12**
41010	415.410	DTL 415.410 RA Energy West Mining	SE	(22,120,356)	(4,998,620)	17,121,736	**Ref. 8.12**
41010	415.413	DTL 415.413 Cntra RA Deer Creek Aband - OR (287843)	OR	2,617,574	905,192	(1,712,382)	**Ref. 8.12**
41110	- - - - - -	Royalties Recovery	SE	-	(993,154)	(993,154)	**Ref. 8.12**
		Total Deferred Income Tax Expense		(19,502,782)	(5,768,702)	**13,734,080**	

PacifiCorp
Oregon General Rate Case - December 2021
Repowering Capital Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Wind Repowering Capital	343	3	1,068,816,985	SG	26.023%	278,134,317	8.13.1
Adjustment to Depreciation Expense:							
Depreciation Expense	403OP	3	34,201,164	SG	26.023%	8,900,043	8.13.1
Depreciation Rates - Proposed	403OP	3	17,500,104	SG	26.023%	4,553,988	8.13.1
Adjustment to Depreciation Reserve:							
Depreciation Reserves	108OP	3	(19,388,387)	SG	26.023%	(5,045,369)	8.13.1
Depreciation Rates - Proposed	108OP	3	(17,500,104)	SG	26.023%	(4,553,988)	8.13.1
Net Book Value Replaced	108OP	3	(724,856,855)	SG	26.023%	(188,626,836)	8.13.1
Adjustment to Operations & Maintenance Expense:							
Incremental O&M Expense	549	3	95,875	SG	26.023%	24,949	8.13.1
Adjustment to Tax:							
Tax - Actual 2020:							
Sch M Adj - Wind Repowering	SCHMAT	3	8,013,152	SG	26.023%	2,085,233	
Sch M Adj - Wind Repowering	SCHMDT	3	82,366,119	SG	26.023%	21,433,833	
DIT Expense - Wind Repowering	41010	3	18,280,864	SG	26.023%	4,757,162	
DIT Expense - Wind Repowering	41010	3	69,306	SG	26.023%	18,035	
ADIT Balance - Wind Repowering	282	3	(17,599,471)	SG	26.023%	(4,579,846)	
Tax - Annualized 2020:							
Sch M Adj - Wind Repowering	SCHMAT	3	3,951,018	SG	26.023%	1,028,159	
DIT Expense - Wind Repowering	41110	3	(971,424)	SG	26.023%	(252,790)	
DIT Expense - Wind Repowering	41010	3	34,404	SG	26.023%	8,953	
ADIT Balance - Wind Repowering	282	3	391,864	SG	26.023%	101,973	
Sch M Adj - Proposed Rate	SCHMAT	3	17,500,104	SG	26.023%	4,553,988	
DIT Expense - Proposed Rate	41110	3	(4,302,681)	SG	26.023%	(1,119,671)	
ADIT Bal - Proposed Rate	282	3	1,316,518	SG	26.023%	342,593	

Description of Adjustment:

This adjustment adds the capital additions and incremental operations and maintenance amounts for the wind repowering projects set to occur before December 2020. This treatment reflects the immediate depreciation of the replaced wind assets as stipulated in UE-352 and UE-369.

The adjustment to wind depreciation expense on wind repowering replaced plant is reflected in Adjustment 6.1 Depreciation and Amortization Expense.

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
Repowering Project Capital Additions Adjustment

Note: Please see Confidential Exhibit PAC/1310_CONF for redacted information.

Project	Source	Project Capital Amount	Depreciation Expense	Depreciation Reserve
[redacted]				
		1,068,816,985	34,201,164	(19,388,387)
		Ref 8.13	**Ref 8.13**	**Ref 8.13**

* Composite Depreciation Rate 3.305%

Project		Existing Rates Depreciation Expense	Proposed Rates** Depreciation Expense	Adjustment to Proposed Rates Depreciation Expense
[redacted]				
		34,201,164	51,701,269	17,500,104
		Above		**Ref 8.13**

** Proposed Composite Depreciation Rate 4.837%

Repowering O&M - Annual

Project	Per OR UE-352/369 (RAC)	
[redacted]		
	95,875	**Ref 8.13**

Net Book Value at Re-Powering

Project	Amount	
Glenrock I	72,052,477	
Glenrock III	26,974,393	
Seven Mile Hill 1	84,842,963	
Seven Mile Hill 2	17,518,675	
High Plains	94,623,476	
McFadden	24,144,119	
Dunlap	100,359,044	
Leaning Juniper	61,726,349	
Marengo I	95,748,543	
Marengo II	51,429,415	
Goodnoe Hills	85,008,240	
Footre Creek	10,429,161	
	724,856,855	**Ref 8.13**

PacifiCorp
Oregon General Rate Case - December 2021
EV 2020 Capital Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
EV 2020 Capital - Wind	343	3	1,234,267,946	SG	26.023%	321,189,013	8.14.2
EV 2020 Capital - Transmission	355	3	767,301,451	SG	26.023%	199,672,037	8.14.2
Adjustment to Depreciation Expense:							
EV 2020 - Wind Depr. Expense	403OP	3	40,787,714	SG	26.023%	10,614,037	8.14.2
EV 2020 - Trans. Depr. Expense	403TP	3	13,402,634	SG	26.023%	3,487,718	8.14.2
EV 2020 - Proposed Wind Depr.	403OP	3	18,916,819	SG	26.023%	4,922,654	8.14.2
EV 2020 - Proposed Trans Depr.	403TP	3	983,888	SG	26.023%	256,034	8.14.2
Adjustment to Depreciation Reserve:							
EV 2020 - Wind Depr. Reserve	108OP	3	(1,705,133)	SG	26.023%	(443,721)	8.14.2
EV 2020 - Trans. Depr. Reserve	108TP	3	(752,845)	SG	26.023%	(195,910)	8.14.2
EV 2020 - Proposed Wind Depr.	108OP	3	(18,916,819)	SG	26.023%	(4,922,654)	8.14.2
EV 2020 - Proposed Trans Depr.	108TP	3	(983,888)	SG	26.023%	(256,034)	8.14.2
Adjustment to Operations & Maintenance Expense:							
Incremental Wind O&M Expense	549	3	15,736,078	SG	26.023%	4,094,942	8.14.3
Adjustment to Tax:							
Actual 2020:							
Schedule M Adj - EV 2020 Wind	SCHMAT	3	1,705,133	SG	26.023%	443,720	
Schedule M Adj - EV 2020 Wind	SCHMDT	3	240,685,840	SG	26.023%	62,632,792	
DIT Exp - EV 2020 Wind	41010	3	58,757,231	SG	26.023%	15,290,178	
DIT Exp - Flowthru - EV 2020 Wind	41010	3	13,398	SG	26.023%	3,487	
ADIT Balance - EV 2020 Wind	282	3	(56,622,286)	SG	26.023%	(14,734,609)	
Annualized 2020:							
Schedule M Adj - EV 2020 Wind	SCHMAT	3	39,082,581	SG	26.023%	10,170,316	
DIT Exp - EV 2020 Wind	41110	3	(9,609,078)	SG	26.023%	(2,500,535)	
ADIT Balance - EV 2020 Wind	282	3	2,940,148	SG	26.023%	765,104	
Incremental for New Depr Rates:							
Schedule M Adj - EV 2020 Wind	SCHMAT	3	18,916,819	SG	26.023%	4,922,654	
DIT Exp - EV 2020 Wind	41110	3	(4,651,003)	SG	26.023%	(1,210,313)	
ADIT Balance - EV 2020 Wind	282	3	1,423,096	SG	26.023%	370,327	
Actual 2020:							
Schedule M Adj - EV 2020 Trans	SCHMAT	3	744,745	SG	26.023%	193,802	
Schedule M Adj - EV 2020 Trans	SCHMDT	3	4,014,622	SG	26.023%	1,044,710	
DIT Exp - EV 2020 Trans	41010	3	10,755	SG	26.023%	2,799	
DIT Exp - Flowthru - EV 2020 Trans	41010	3	803,952	SG	26.023%	209,209	
ADIT Balance - EV 2020 Trans	282	3	1,748,689	SG	26.023%	455,055	

Description of Adjustment:

This adjustment adds the capital additions, and incremental operations and maintenance amounts for the EV 2020 wind and transmission projects set to occur before the end of 2020. For more details on EV 2020 projects, please refer to direct testimonies of company witnesses Mr. Rick T. Link, Mr. Chad A. Teply, Mr. Timothy J. Hemstreet, and Mr. Richard A. Vail.

PacifiCorp
Oregon General Rate Case - December 2021
EV 2020 Capital Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Annualized 2020:							
Schedule M Adj - EV 2020 Trans	SCHMAT	3	12,657,889	SG	26.023%	3,293,916	
DIT Exp - EV 2020 Trans	41110	3	(3,112,145)	SG	26.023%	(809,862)	
ADIT Balance - EV 2020 Trans	282	3	952,241	SG	26.023%	247,798	
Incremental for New Depr Rates:							
Schedule M Adj - EV 2020 Trans	SCHMAT	3	983,888	SG	26.023%	256,034	
DIT Exp - EV 2020 Trans	41110	3	(241,905)	SG	26.023%	(62,950)	
ADIT Balance - EV 2020 Trans	282	3	74,017	SG	26.023%	19,261	

Description of Adjustment:

This adjustment adds the capital additions, and incremental operations and maintenance amounts for the EV 2020 wind and transmission projects set to occur before the end of 2020. For more details on EV 2020 projects, please refer to direct testimonies of company witnesses Mr. Rick T. Link, Mr. Chad A. Teply, Mr. Timothy J. Hemstreet, and Mr. Richard A. Vail.

REDACTED

PacifiCorp
Oregon General Rate Case - December 2021
EV 2020 Capital Additions

EV 2020 CAPITAL ADDITIONS

Note: Please see Confidential Exhibit PAC/1311_CONF for redacted information.

Electric Plant in Service

	Account	Factor	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Other Plant Wind	343	SG	[redacted]												1,234,267,946
Transmission Plant	355	SG													767,301,451

Depreciation Expense*

	Account	Factor	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Other Plant Wind	403OP	SG	[redacted]												1,699,959
Transmission Plant	403TP	SG													566,543

Depreciation Reserve

	Account	Factor	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Other Plant Wind	108OP	SG	[redacted]												(1,705,133)
Transmission Plant	108TP	SG													(752,845)

	12 ME Jun 2019	Dec 2020	Adjustment	
343	-	1,234,267,946	**1,234,267,946**	**Ref. 8.14**
355	-	767,301,451	**767,301,451**	**Ref. 8.14**
403OP	-	40,787,714	**40,787,714**	**Ref. 8.14**
403TP	-	13,402,634	**13,402,634**	**Ref. 8.14**
108OP	-	(1,705,133)	**(1,705,133)**	**Ref. 8.14**
108TP	-	(752,845)	**(752,845)**	**Ref. 8.14**

	December 2020 EPIS Balance	Annualized Depreciation Expense	Proposed Rates** Depreciation Expense	Adjustment to Proposed Rates Depreciation Expense	
Other Prod.	1,234,267,946	40,787,714	59,704,533	18,916,819	**Ref. 8.14**
Transmission	767,301,451	13,402,634	14,386,522	983,888	**Ref. 8.14**

**Composite Depreciation Rate - Wind*	*3.305%*
**Composite Depreciation Rate - Trans*	*1.747%*
***Proposed Composite Depreciation Rate - Wind*	*4.837%*
*** Proposed Composite Depreciation Rate - Trans*	*1.875%*

PacifiCorp
Oregon General Rate Case - December 2021
EV 2020 Capital Additions

REDACTED

Note: Please see Confidential Exhibit PAC/1311_CONF for redacted information.

Project	**Date**	**Project Capital Amount**	
Transmission			
[redacted]			
		767,301,451	**Ref 8.14.2**
New Wind			
[redacted]			
		1,234,267,946	**Ref 8.14.2**
Total		2,001,569,397	

Project		**2021 O&M**	
[redacted]			
		15,736,078	**Ref 8.14**

PacifiCorp
Oregon General Rate Case - December 2021
Cholla Unit 4 Retirement

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove O&M expense	506	3	(30,310,513)	SG	26.023%	(7,887,593)	8.15.1
Remove Depr. expense	403SP	3	(25,709,005)	SG	26.023%	(6,690,160)	6.1.4
Adjustment to Rate Base:							
Remove Gross Unrecovered Plant	312	3	(549,199,953)	SG	26.023%	(142,916,286)	8.5.2
Remove Accumulated Depreciation	108SP	3	363,952,120	SG	26.023%	94,709,923	6.2.2
Remove M&S Inventory	154	3	(6,622,205)	SG	26.023%	(1,723,272)	8.15.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	(25,709,005)	SG	26.023%	(6,690,160)	Above
Deferred Income Tax Expense	41110	3	6,320,970	SG	26.023%	1,644,883	
Accumulated Def Inc Tax Balance	282	3	(6,320,970)	SG	26.023%	(1,644,883)	

Description of Adjustment:

Consistent with the IRP, the Company will be closing Cholla Unit 4 in December 2020. Recovery of Cholla plant will be included in a separate tariff rider. This adjustment removes Cholla-related expenses and rate base balances from test period results.

PacifiCorp
Oregon General Rate Case - December 2021
Cholla Unit 4 Retirement
Cholla Unit 4 - Non-EPIS Balances for Removal

	FERC account	12 ME June 2019
O&M Expenses	506	$ 30,310,513
		Ref 8.15

	FERC account	EOP June 2019
Material & Supplies	154	$ 6,622,205
		Ref 8.15

PacifiCorp
Oregon General Rate Case - December 2021
Klamath Facilities Capital Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Add Depreciation Expense	403HP	3	641,868	SG-P	26.023%	167,031	8.16.1
Adjustment to Rate Base							
Add Capital Additions	332	3	3,209,341	SG-P	26.023%	835,155	8.16.1
Add Depreciation Reserve	108HP	3	(184,175)	SG-P	26.023%	(47,927)	8.16.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	641,868	SG	26.023%	167,031	
Schedule M Adjustment	SCHMDT	3	120,348	SG	26.023%	31,318	
Deferred Income Tax Expense	41110	3	(128,220)	SG	26.023%	(33,366)	
Accumulated Def Inc Tax Balance	282	3	128,220	SG	26.023%	33,366	

Description of Adjustment:

Consistent with the Klamath Hydroelectric Settlement Agreement (KHSA), depreciation rates for the Klamath assets were previously approved by the Commission to provide for full depreciation of the Klamath assets by 12/31/2019. The timing of when FERC will transfer the license, and when PacifiCorp’s operations will ultimately cease, remains uncertain. As the current project licensee, PacifiCorp's obligations under the license and FERC regulations continue to require capital investments to support ongoing project operations. This adjustments adds into test period results capital additions and depreciation through calendar year 2020.

PacifiCorp
Oregon General Rate Case - December 2021
Klamath Facilities Capital Additions

Proposed Depreciation Life	5 Years
Proposed Depreciation Rate	20%

Project Description	FERC	Allocation	Month Placed In-Service	In-Service Amount
Klamath ongoing capital additions	332	SG-P	2/1/2020	12,578
Klamath ongoing capital additions	332	SG-P	3/1/2020	524,085
Klamath ongoing capital additions	332	SG-P	4/1/2020	12,475
Klamath ongoing capital additions	332	SG-P	5/1/2020	95,912
Klamath ongoing capital additions	332	SG-P	6/1/2020	287,842
Klamath ongoing capital additions	332	SG-P	7/1/2020	165,693
Klamath ongoing capital additions	332	SG-P	8/1/2020	173,756
Klamath ongoing capital additions	332	SG-P	11/1/2020	581,539
Klamath ongoing capital additions	332	SG-P	12/1/2020	1,355,462
			Total In-Service	**3,209,341**

Month	Gross Plant In-Service	Depreciation Expense	Depreciation Reserve
Jan-20	-	-	-
Feb-20	12,578	105	(105)
Mar-20	536,663	4,577	(4,682)
Apr-20	549,138	9,048	(13,730)
May-20	645,050	9,952	(23,682)
Jun-20	932,892	13,150	(36,831)
Jul-20	1,098,584	16,929	(53,760)
Aug-20	1,272,340	19,758	(73,518)
Sep-20	1,272,340	21,206	(94,724)
Oct-20	1,272,340	21,206	(115,929)
Nov-20	1,853,880	26,052	(141,981)
Dec-20	**3,209,341**	42,194	**(184,175)**
	Ref 8.16		**Ref 8.16**
Annualized Depreciation Expense		**641,868.28**	
		Ref 8.16	

Oregon General Rate Case - December 2021
Twelve Months Ending December 31, 2021
ANNUAL EMBEDDED COSTS
YEAR END BALANCE

2020 Protocol ECD

Company Owned Hydro - West

Account	Description	Amount	Mwh	$/Mwh	Differential
535 - 545	Hydro Operation & Maintenance Expense	33,955,817			
403HP	Hydro Depreciation Expense	18,170,182			
404IP / 404HP	Hydro Relicensing Amortization	3,007,134			
	Total West Hydro Operating Expense	**55,133,134**			
330 - 336	Hydro Electric Plant in Service	963,135,717			
302 & 182M	Hydro Relicensing	175,004,296			
108HP	Hydro Accumulated Depreciation Reserve	(427,212,903)			
111IP	Hydro Relicensing Accumulated Reserve	(112,901,800)			
154	Materials and Supplies	7,954			
	West Hydro Net Rate Base	**598,033,264**			
	Pre-tax Return	9.46%			
	Rate Base Revenue Requirement	**56,552,021**			
	Annual Embedded Cost				
	West Hydro-Electric Resources	**111,685,155**	3,364,706	33.19	(60,985,577)

Mid C Contracts

Account	Description	Amount	Mwh	$/Mwh	Differential
555	Annual Mid-C Contracts Costs	2,136,095	93,504	22.84	(2,662,365)
	Grant Reasonable Portion	-			-
		2,136,095			(2,662,365)

Qualified Facilities

Account	Description	Amount	Mwh	$/Mwh	Differential
555	Utah Annual Qualified Facilities Costs				
555	Oregon Annual Qualified Facilities Costs				
555	Idaho Annual Qualified Facilities Costs				
555	WYU Annual Qualified Facilities Costs				
555	WYP Annual Qualified Facilities Costs				
555	California Annual Qualified Facilities Costs				
555	Washington Annual Qualified Facilities Costs				
	Total Qualified Facilities Costs	-			-

All Other Generation Resources
(Excl. West Hydro, Mid C, and QF)

Account	Description	Amount	Mwh	$/Mwh
500 - 514	Steam Operation & Maintenance Expense	991,783,415		
535 - 545	East Hydro Operation & Maintenance Expense	10,122,927		
546 - 554	Other Generation Operation & Maintenance Expense	33,526,100		
555	Other Purchased Power Contracts	0		
40910	Production Tax Credit	0		
4118	SO2 Emission Allowances	(173)		
456	James River / Little Mountain Offset	0		
456	REC Revenues	-		
403SP	Steam Depreciation Expense	203,400,280		
403HP	East Hydro Depreciation Expense	5,443,568		
403OP	Other Generation Depreciation Expense	9,937,655		
403MP	Mining Depreciation Expense	0		
404IP	East Hydro Relicensing Amortization	331,288		
406	Amortization of Plant Acquisition Costs	0		
	Total All Other Operating Expenses	**1,254,545,060**		
310 - 316	Steam Electric Plant in Service	6,786,078,794		
330 - 336	East Hydro Electric Plant in Service	196,682,248		
302 & 186M	East Hydro Relicensing	9,951,392		
340 - 346	Other Electric Plant in Service	264,435,483		
399	Mining	84,739,827		
108SP	Steam Accumulated Depreciation Reserve	(3,812,858,733)		
108OP	Other Generation Accumulated Depreciation Reserve	(126,344,870)		
108MP	Other Accumulated Depreciation Reserve	0		
108HP	East Hydro Accumulated Depreciation Reserve	(91,255,106)		
111IP	East Hydro Relicensing Accumulated Reserve	(7,006,278)		
114	Electric Plant Acquisition Adjustment	141,186,242		
115	Accumulated Provision Acquisition Adjustment	(127,891,505)		
151	Fuel Stock	158,803,758		
253.16 - 253.19	Joint Owner WC Deposit	(5,044,318)		
253.98	SO2 Emission Allowances	0		
154	Materials & Supplies	84,497,110		
154	East Hydro Materials & Supplies			
	Total Net Rate Base	**3,555,974,043**		
	Pre-tax Return	9.46%		
	Rate Base Revenue Requirement	**336,264,772**		
	Annual Embedded Cost			
	All Other Generation Resources	**1,590,809,831**	30,998,924	51.32
	Total Annual Embedded Costs	**1,704,631,081**	**34,457,134**	**49.47**

Oregon General Rate Case
Pro Forma Factors December 31, 2021
2020 Protocol Factors

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2021

DESCRIPTION	2020 PROTOCOL FACTOR	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Situs	S	-	-	-	-	-	-	-			Situs
System Generation	SG	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	0.0000%	0.0000%	Pg 10.16
Divisional Generation - Pac. Power	DGP	3.2512%	55.0569%	16.6974%	0.0000%	0.0000%	24.9944%	0.0000%	0.0000%	0.0000%	Pg 10.16
Divisional Generation - R.M.P.	DGU	0.0000%	0.0000%	0.0000%	83.4313%	11.1832%	5.3318%	0.0537%	0.0000%	0.0000%	Pg 10.16
System Capacity	SC	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%	0.0000%	0.0000%	Pg 10.16
System Energy	SE	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	0.0000%	0.0000%	Pg 10.16
System Overhead	SO	2.2317%	27.2153%	7.6983%	43.4986%	5.7390%	13.5967%	0.0203%	0.0000%	0.0000%	Pg 10.7
Gross Plant-System	GPS	2.2317%	27.2153%	7.6983%	43.4986%	5.7390%	13.5967%	0.0203%	0.0000%	0.0000%	Pg 10.6
System Net Plant	SNP	2.0913%	26.2921%	7.3993%	44.8609%	5.7476%	13.5695%	0.0207%	0.0186%	0.0000%	Pg 10.6
Division Net Plant Distribution	SNPD	3.6237%	26.7564%	6.1474%	48.1320%	5.1052%	10.2353%	0.0000%	0.0000%	0.0000%	Pg 10.5
Customer - System	CN	2.3966%	31.2171%	6.9361%	47.8254%	4.2022%	7.4227%	0.0000%	0.0000%	0.0000%	Pg 10.10
CIAC	CIAC	3.6237%	26.7564%	6.1474%	48.1320%	5.1052%	10.2353%	0.0000%	0.0000%	0.0000%	Pg 10.10
Bad Debt Expense	BADDEBT	5.4344%	35.6619%	12.4044%	33.7727%	5.3363%	7.3903%	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%	0.6110%	Fixed
Accumulated Investment Tax Credit 1985	ITC85	5.4200%	67.6900%	13.3600%	0.0000%	0.0000%	11.6100%	0.0000%	0.0000%	1.9200%	Fixed
Accumulated Investment Tax Credit 1986	ITC86	4.7890%	64.6080%	13.1260%	0.0000%	0.0000%	15.5000%	0.0000%	0.0000%	1.9770%	Fixed
Accumulated Investment Tax Credit 1988	ITC88	4.2700%	61.2000%	14.9600%	0.0000%	0.0000%	16.7100%	0.0000%	0.0000%	2.8600%	Fixed
Accumulated Investment Tax Credit 1989	ITC89	4.8806%	56.3558%	15.2688%	0.0000%	0.0000%	20.6776%	0.0000%	0.0000%	2.8172%	Fixed
Accumulated Investment Tax Credit 1990	ITC90	1.5047%	15.9356%	3.9132%	46.9355%	13.9815%	17.3435%	0.0000%	0.0000%	0.3860%	Fixed
Other Electric	OTHER	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	Situs
Non-Utility	NUTIL	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	Situs
System Net Steam Plant	SNPPS	1.5304%	25.9158%	7.8597%	44.1534%	5.9198%	14.5927%	0.0282%	0.0000%	0.0000%	Pg 10.3
System Net Transmission Plant	SNPT	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	0.0000%	0.0000%	Pg 10.4
System Net Production Plant	SNPP	1.5338%	25.9767%	7.8773%	44.0285%	5.9021%	14.6073%	0.0283%	0.0460%	0.0000%	Pg 10.4
System Net Hydro Plant	SNPPH	1.5277%	25.8705%	7.8459%	43.7403%	5.8630%	14.5398%	0.0282%	0.5846%	0.0000%	Pg 10.3
System Net Other Production Plant	SNPPO	1.5366%	26.0259%	7.8917%	43.9955%	5.8972%	14.6247%	0.0283%	0.0000%	0.0000%	Pg 10.4
System Net General Plant	SNPG	2.6987%	28.5679%	6.3596%	41.3210%	6.5072%	14.5344%	0.0112%	0.0000%	0.0000%	Pg 10.5
System Net Intangible Plant	SNPI	2.0845%	26.3384%	7.7270%	43.3305%	6.3193%	14.1795%	0.0208%	0.0000%	0.0000%	Pg 10.6
Trojan Plant Allocator	TROJP	1.5242%	25.8827%	7.8352%	43.9001%	5.9978%	14.8311%	0.0290%	0.0000%	0.0000%	Pg 10.12
Trojan Decommissioning Allocator	TROJD	1.5220%	25.8580%	7.8251%	43.8829%	6.0155%	14.8674%	0.0291%	0.0000%	0.0000%	Pg 10.12
DIT Balance	DITBAL	2.2266%	24.6785%	6.4832%	44.3496%	5.8380%	14.6629%	0.2376%	0.0000%	1.5235%	Pg 10.9
Tax Depreciation	TAXDEPR	1.9379%	26.2736%	5.8206%	44.7704%	5.7046%	13.7111%	0.0220%	0.0000%	1.7599%	Pg 10.13
SCHMAT Depreciation Expense	SCHMDEXP	2.0158%	26.7258%	7.8032%	43.6198%	5.7638%	14.0485%	0.0230%	0.0000%	0.0000%	Pg 10.12
System Generation Cholla Transaction	SGCT	1.5371%	26.0300%	7.8943%	44.0100%	5.8991%	14.6295%	0.0000%	0.0000%	0.0000%	Pg 10.2

CALCULATION OF INTERNAL FACTORS
Pro Forma Factors December 31, 2021

DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
STEAM :											
STEAM PRODUCTION PLANT											
	S	0	0	0	0	0	0	0	0	0	0
	DGP	0	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	6,866,740,006	105,521,343	1,786,906,522	541,925,792	3,021,193,806	404,963,909	1,004,282,668	1,945,966	0	0

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2021

	SSGCH	0	0	0	0	0	0	0	0	0	0
		6,866,740,006	105,521,343	1,786,906,522	541,925,792	3,021,193,806	404,963,909	1,004,282,668	1,945,966	0	0
LESS ACCUMULATED DEPRECIATION											
	S	10,702,263	0	0	0	8,775,068	1,213,075	714,120	0	0	0
	DGP	(759,016,718)	(11,663,826)	(197,516,132)	(59,901,895)	(333,948,366)	(44,762,781)	-111,008,620	(215,098)	0	0
	DGU	(726,882,090)	(11,170,013)	(189,153,855)	(57,365,817)	(319,809,934)	(42,867,651)	-106,308,828	(205,991)	0	0
	SG	(2,537,439,356)	(38,992,886)	(660,308,520)	(200,255,701)	(1,116,409,833)	(149,644,716)	-371,108,614	(719,085)	0	0
	SG-W	0	0	0	0	0	0	0	0	0	0
	SSGCH	(246,321,600)	(3,785,229)	(64,099,365)	(19,439,796)	(108,375,341)	(14,526,742)	-36,025,321	(69,805)	0	0
		(4,258,957,500)	(65,611,955)	(1,111,077,872)	(336,963,209)	(1,869,768,407)	(250,588,814)	(623,737,264)	(1,209,979)	0	0
TOTAL NET STEAM PLANT		2,607,782,507	39,909,389	675,828,650	204,962,583	1,151,425,400	154,375,095	380,545,404	735,987	0	0
SNPPS											
SYSTEM NET PLANT PRODUCTION STEAM		100.0000%	1.5304%	25.9158%	7.8597%	44.1534%	5.9198%	14.5927%	0.0282%	0.0000%	0.0000%

NUCLEAR :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**
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%

HYDRO :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
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	1,129,544,110	17,357,729	293,937,113	89,144,060	496,971,149	66,614,521	165,199,435	320,102	0	0
		1,129,544,110	17,357,729	293,937,113	89,144,060	496,971,149	66,614,521	165,199,435	320,102	0	0
LESS ACCUMULATED DEPRECIATION (incl hydro amortization)											
	S	3,575,830	0	0	0	0	0	0	0	3,575,830	0
	DGP	(175,334,101)	(2,694,363)	(45,626,549)	(13,837,435)	(77,142,618)	(10,340,275)	(25,643,172)	(49,688)	0	0
	DGU	(30,353,650)	(466,445)	(7,898,819)	(2,395,522)	(13,354,846)	(1,790,097)	(4,439,318)	(8,602)	0	0
	SG	(315,763,646)	(4,852,347)	(82,170,013)	(24,920,190)	(138,928,104)	(18,622,065)	(46,181,442)	(89,484)	0	0
		(517,875,566)	(8,013,155)	(135,695,381)	(41,153,147)	(229,425,568)	(30,752,438)	(76,263,933)	(147,774)	3,575,830	0
TOTAL NET HYDRO PRODUCTION PLANT		611,668,544	9,344,574	158,241,733	47,990,913	267,545,580	35,862,083	88,935,502	172,327	3,575,830	0
SNPPH											
SYSTEM NET PLANT PRODUCTION HYDRO		100.0000%	1.5277%	25.8705%	7.8459%	43.7403%	5.8630%	14.5398%	0.0282%	0.5846%	0.0000%

OTHER :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
OTHER PRODUCTION PLANT (EXCLUDES EXPERIMENTAL)											
	S	204,809	0	204,809	0	0	0	0	0	0	0
	DGP & DGU	0	0	0	0	0	0	0	0	0	0

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	SG	5,375,374,484	82,603,497	1,398,813,952	424,226,645	2,365,030,288	317,011,080	786,165,695	1,523,328	0	0
	SSGCT	0	0	0	0	0	0	0	0	0	0
		5,375,579,294	82,603,497	1,399,018,761	424,226,645	2,365,030,288	317,011,080	786,165,695	1,523,328	0	0
LESS ACCUMULATED DEPRECIATION											
	S	(4,278)	0	(4,278)	0	0	0	0	0	0	0
	DGP	376,504,462	5,785,752	97,976,373	29,713,879	165,652,544	22,204,236	55,064,981	106,698	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	(1,194,877,600)	(18,361,710)	(310,938,608)	(94,300,205)	(525,716,250)	(70,467,544)	(174,754,667)	(338,617)	0	0
	SSGCT	(36,871,542)	(566,606)	(9,594,946)	(2,909,916)	(16,222,556)	(2,174,488)	(5,392,581)	(10,449)	0	0
		(855,248,958)	(13,142,564)	(222,561,459)	(67,496,243)	(376,286,262)	(50,437,796)	(125,082,267)	(242,368)	0	0
TOTAL NET OTHER PRODUCTION PLANT		4,520,330,336	69,460,933	1,176,457,302	356,730,402	1,988,744,027	266,573,284	661,083,427	1,280,960	0	0
SNPPO											
SYSTEM NET PLANT PRODUCTION OTHER		100.0000%	1.5366%	26.0259%	7.8917%	43.9955%	5.8972%	14.6247%	0.0283%	0.0000%	0.0000%
PRODUCTION :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
TOTAL PRODUCTION PLANT											
	S	204,809	0	204,809	0	0	0	0	0	0	0
	DGP & DGU	0	0	0	0	0	0	0	0	0	0
	SG	13,371,658,601	205,482,569	3,479,657,587	1,055,296,497	5,883,195,243	788,589,511	1,955,647,798	3,789,396	0	0
	SSGCH	0	0	0	0	0	0	0	0	0	0
	SSGCT	0	0	0	0	0	0	0	0	0	0
		13,371,863,410	205,482,569	3,479,862,396	1,055,296,497	5,883,195,243	788,589,511	1,955,647,798	3,789,396	0	0
LESS ACCUMULATED DEPRECIATION											
	S	14,273,815	0	(4,278)	0	8,775,068	1,213,075	714,120	0	3,575,830	0
	DGP	0	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	(5,618,466,201)	(86,339,092)	(1,462,072,816)	(443,411,538)	(2,471,984,562)	(331,347,340)	(821,718,635)	(1,592,218)	0	0
	SSGCH	0	0	0	0	0	0	0	0	0	0
	SSGCT	0	0	0	0	0	0	0	0	0	0
		(5,604,192,387)	(86,339,092)	(1,462,077,094)	(443,411,538)	(2,463,209,494)	(330,134,265)	(821,004,515)	(1,592,218)	3,575,830	0
TOTAL NET PRODUCTION PLANT		7,767,671,023	119,143,476	2,017,785,302	611,884,960	3,419,985,749	458,455,246	1,134,643,282	2,197,178	3,575,830	0
SNPP											
SYSTEM NET PRODUCTION PLANT		100.0000%	1.5338%	25.9767%	7.8773%	44.0285%	5.9021%	14.6073%	0.0283%	0.0460%	0.0000%
TRANSMISSION :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
TRANSMISSION PLANT											
	DGP	0	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	7,581,656,310	116,507,478	1,972,946,565	598,347,265	3,335,739,094	447,125,882	1,108,841,462	2,148,567	0	0
		7,581,656,310	116,507,478	1,972,946,565	598,347,265	3,335,739,094	447,125,882	1,108,841,462	2,148,567	0	0
LESS ACCUMULATED DEPRECIATION											
	DGP	(351,699,893)	(5,404,580)	(91,521,571)	(27,756,292)	(154,739,154)	(20,741,395)	(51,437,233)	(99,668)	0	0
	DGU	(418,414,202)	(6,429,780)	(108,882,391)	(33,021,412)	(184,091,781)	(24,675,851)	(61,194,414)	(118,574)	0	0
	SG	(1,193,013,954)	(18,333,071)	(310,453,638)	(94,153,125)	(524,896,292)	(70,357,636)	(174,482,103)	(338,088)	0	0
		(1,963,128,049)	(30,167,431)	(510,857,599)	(154,930,829)	(863,727,227)	(115,774,881)	(287,113,750)	(556,331)	0	0
TOTAL NET TRANSMISSION PLANT		5,618,528,261	86,340,046	1,462,088,966	443,416,436	2,472,011,867	331,351,000	821,727,711	1,592,236	0	0
SNPT											
SYSTEM NET PLANT TRANSMISSION		100.0000%	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	0.0000%	0.0000%
DISTRIBUTION :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**		
DISTRIBUTION PLANT - PACIFIC POWER											

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		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
	S	3,832,700,856	312,274,943	2,290,848,762	551,435,929	0	0	678,141,221	0
LESS ACCUMULATED DEPRECIATION									
	S	(1,779,029,710)	(147,062,217)	(1,070,959,180)	(271,158,882)	0	0	(289,849,432)	0
		2,053,671,146	165,212,726	1,219,889,583	280,277,048	0	0	388,291,789	0
DNPDP									
DIVISION NET PLANT DISTRIBUTION PACIFIC POWER		100.0000%	8.0448%	59.4004%	13.6476%	0.0000%	0.0000%	18.9072%	0.0000%
DISTRIBUTION PLANT - ROCKY MOUNTAIN POWER									
	S	3,809,010,231	0	0	0	3,279,501,681	392,387,444	137,121,106	0
LESS ACCUMULATED DEPRECIATION									
	S	(1,303,433,903)	0	0	0	(1,085,042,946)	(159,630,533)	(58,760,424)	0
		2,505,576,328	0	0	0	2,194,458,734	232,756,911	78,360,682	0
DNPDU									
DIVISION NET PLANT DISTRIBUTION R.M.P.		100.0000%	0.0000%	0.0000%	0.0000%	87.5830%	9.2896%	3.1275%	0.0000%
TOTAL NET DISTRIBUTION PLANT		4,559,247,474	165,212,726	1,219,889,583	280,277,048	2,194,458,734	232,756,911	466,652,471	0
DNPD & SNPD									
SYSTEM NET PLANT DISTRIBUTION		100.0000%	3.6237%	26.7564%	6.1474%	48.1320%	5.1052%	10.2353%	0.0000%

GENERAL :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**
GENERAL PLANT									
	S	729,616,912	23,758,164	232,415,134	49,657,933	269,991,497	50,840,840	102,953,345	0
	DGP	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0
	SE	3,631,101	52,810	911,460	272,977	1,574,308	238,115	580,249	1,182
	SG	319,706,957	4,912,944	83,196,167	25,231,397	140,663,062	18,854,621	46,758,164	90,602
	SO	330,642,794	7,378,891	89,985,469	25,454,023	143,825,070	18,975,680	44,956,391	67,270
	CN	14,495,900	347,405	4,525,194	1,005,448	6,932,721	609,147	1,075,985	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	(19,601,761)	(221,970)	(5,817,126)	(1,068,951)	(9,723,167)	(798,534)	(1,968,312)	(3,701)
		1,378,491,903	36,228,242	405,216,298	100,552,828	553,263,491	88,719,868	194,355,823	155,354
LESS ACCUMULATED DEPRECIATION									
	S	(280,757,968)	(8,680,736)	(96,383,891)	(27,203,031)	(93,399,743)	(19,047,524)	(36,043,043)	0
	DGP	(843,233)	(12,958)	(219,431)	(66,548)	(371,001)	(49,729)	(123,326)	(239)
	DGU	(2,907,693)	(44,683)	(756,658)	(229,476)	(1,279,312)	(171,480)	(425,259)	(824)
	SE	(1,759,892)	(25,595)	(441,759)	(132,304)	(763,022)	(115,408)	(281,230)	(573)
	SG	(124,641,305)	(1,915,366)	(32,434,949)	(9,836,740)	(54,839,056)	(7,350,683)	(18,229,189)	(35,322)
	SO	(110,486,410)	(2,465,704)	(30,069,222)	(8,505,625)	(48,060,069)	(6,340,845)	(15,022,466)	(22,479)
	CN	(4,849,240)	(116,216)	(1,513,790)	(336,348)	(2,319,168)	(203,775)	(359,944)	0
	SSGCT	(110,482)	(1,698)	(28,750)	(8,719)	(48,609)	(6,516)	(16,158)	(31)
	SSGCH	(2,712,809)	(41,688)	(705,944)	(214,096)	(1,193,568)	(159,987)	(396,757)	(769)
		(529,069,032)	(13,304,642)	(162,554,395)	(46,532,888)	(202,273,550)	(33,445,948)	(70,897,373)	(60,237)
TOTAL NET GENERAL PLANT		849,422,871	22,923,600	242,661,903	54,019,940	350,989,941	55,273,920	123,458,450	95,117
SNPG									
SYSTEM NET GENERAL PLANT		100.0000%	2.6987%	28.5679%	6.3596%	41.3210%	6.5072%	14.5344%	0.0112%

MINING :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**
GENERAL MINING PLANT									
	SE	84,739,827	1,232,428	21,270,957	6,370,519	36,739,977	5,556,946	13,541,404	27,596
LESS ACCUMULATED DEPRECIATION									
	SE	0	0	0	0	0	0	0	0
		84,739,827	1,232,428	21,270,957	6,370,519	36,739,977	5,556,946	13,541,404	27,596
SNPM									

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SYSTEM NET PLANT MINING		100.0000%	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%

INTANGIBLE :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**
INTANGIBLE PLANT									
	S	(7,815,888)	1,118,099	5,489,081	2,036,363	(26,215,920)	4,369,593	5,386,895	0
	DGP	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0
	SE	(1,106,269)	(16,089)	(277,690)	(83,166)	(479,636)	(72,545)	(176,781)	(360)
	CN	175,494,022	4,205,841	54,784,072	12,172,421	83,930,701	7,374,612	13,026,374	0
	SG	360,776,369	5,544,058	93,883,509	28,472,611	158,732,576	21,276,677	52,764,697	102,240
	SO	403,194,225	8,998,007	109,730,568	31,039,283	175,383,945	23,139,426	54,820,965	82,031
	SSGCT	0	0	0	0	0	0	0	0
	SSGCH	0	0	0	0	0	0	0	0
		930,542,460	19,849,917	263,609,540	73,637,512	391,351,667	56,087,763	125,822,150	183,912
LESS ACCUMULATED AMORTIZATION									
	S	34,376,581	(5,417)	(114,464)	(9,071)	35,543,854	(963,860)	(74,461)	0
	DGP	0	0	0	0	0	0	0	0
	DGU	(489,827)	(7,527)	(127,466)	(38,657)	(215,512)	(28,887)	(71,639)	(139)
	SE	1,106,269	16,089	277,690	83,166	479,636	72,545	176,781	360
	CN	(152,460,423)	(3,653,824)	(47,593,660)	(10,574,790)	(72,914,793)	(6,406,694)	(11,316,662)	0
	SG	(215,898,977)	(3,317,724)	(56,182,597)	(17,038,831)	(94,990,148)	(12,732,577)	(31,575,915)	(61,184)
	SO	(294,501,804)	(6,572,339)	(80,149,586)	(22,671,765)	(128,104,236)	(16,901,539)	(40,042,422)	(59,917)
	SSGCT	0	0	0	0	0	0	0	0
	SSGCH	(21,945)	(337)	(5,711)	(1,732)	(9,655)	(1,294)	(3,210)	(6)
		(627,890,126)	(13,541,080)	(183,895,794)	(50,251,680)	(260,210,854)	(36,962,305)	(82,907,526)	(120,886)
TOTAL NET INTANGIBLE PLANT		302,652,334	6,308,836	79,713,746	23,385,832	131,140,813	19,125,457	42,914,624	63,026
SNPI									
SYSTEM NET INTANGIBLE PLANT		100.0000%	2.0845%	26.3384%	7.7270%	43.3305%	6.3193%	14.1795%	0.0208%

GROSS PLANT :	**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
PRODUCTION PLANT	13,371,863,410	205,482,569	3,479,862,396	1,055,296,497	5,883,195,243	788,589,511	1,955,647,798	3,789,396	0	0
TRANSMISSION PLANT	7,581,656,310	116,507,478	1,972,946,565	598,347,265	3,335,739,094	447,125,882	1,108,841,462	2,148,567	0	0
DISTRIBUTION PLANT	7,641,711,087	312,274,943	2,290,848,762	551,435,929	3,279,501,681	392,387,444	815,262,327	0	0	0
GENERAL PLANT	1,463,231,730	37,460,670	426,487,256	106,923,347	590,003,468	94,276,813	207,897,227	182,950	0	0
INTANGIBLE PLANT	930,542,460	19,849,917	263,609,540	73,637,512	391,351,667	56,087,763	125,822,150	183,912	0	0
TOTAL GROSS PLANT	30,989,004,997	691,575,576	8,433,754,519	2,385,640,549	13,479,791,152	1,778,467,413	4,213,470,964	6,304,825	0	0
GPS										
GROSS PLANT-SYSTEM FACTOR	100.0000%	2.2317%	27.2153%	7.6983%	43.4986%	5.7390%	13.5967%	0.0203%	0.0000%	0.0000%
ACCUMULATED DEPRECIATION AND AMORTIZATION										
PRODUCTION PLANT	(5,604,192,387)	(86,339,092)	(1,462,077,094)	(443,411,538)	(2,463,209,494)	(330,134,265)	(821,004,515)	(1,592,218)	3,575,830	0
TRANSMISSION PLANT	(1,963,128,049)	(30,167,431)	(510,857,599)	(154,930,829)	(863,727,227)	(115,774,881)	(287,113,750)	(556,331)	0	0
DISTRIBUTION PLANT	(3,082,463,613)	(147,062,217)	(1,070,959,180)	(271,158,882)	(1,085,042,946)	(159,630,533)	(348,609,856)	0	0	0
GENERAL PLANT	(529,069,032)	(13,304,642)	(162,554,395)	(46,532,888)	(202,273,550)	(33,445,948)	(70,897,373)	(60,237)	0	0
INTANGIBLE PLANT	(627,890,126)	(13,541,080)	(183,895,794)	(50,251,680)	(260,210,854)	(36,962,305)	(82,907,526)	(120,886)	0	0
	(11,806,743,206)	(290,414,463)	(3,390,344,062)	(966,285,816)	(4,874,464,070)	(675,947,932)	(1,610,533,020)	(2,329,672)	3,575,830	0
NET PLANT	19,182,261,791	401,161,113	5,043,410,457	1,419,354,733	8,605,327,081	1,102,519,481	2,602,937,943	3,975,153	3,575,830	0
SNP										
SYSTEM NET PLANT FACTOR (SNP)	100.0000%	2.0913%	26.2921%	7.3993%	44.8609%	5.7476%	13.5695%	0.0207%	0.0186%	0.0000%

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		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
NON-UTILITY RELATED INTEREST PERCENTAGE		0.0000%									
INT											
INTEREST FACTOR SNP - NON-UTILITY		100.0000%	2.0913%	26.2921%	7.3993%	44.8609%	5.7476%	13.5695%	0.0207%	0.0186%	0.0000%
TOTAL GROSS PLANT (LESS SO FACTOR)		30,257,055,405	675,240,800	8,234,552,151	2,329,292,544	13,161,403,141	1,736,460,627	4,113,950,235	6,155,907	0	0
SO											
SYSTEM OVERHEAD FACTOR (SO)		100.0000%	2.2317%	27.2153%	7.6983%	43.4986%	5.7390%	13.5967%	0.0203%	0.0000%	0

IBT **INCOME BEFORE TAXES**		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
INCOME BEFORE STATE TAXES		647,788,920	8,615,653	190,310,563	32,389,282	225,343,337	38,127,931	97,364,061	13,098,501	59,099,738	(16,560,145)
Interest Synchronization		970,812	20,303	255,246	71,833	435,515	55,798	131,734	201	181	-
		648,759,732	8,635,956	190,565,809	32,461,115	225,778,852	38,183,730	97,495,795	13,098,702	59,099,919	(16,560,145)
INCOME BEFORE TAXES (FACTOR)		100.0000%	1.3311%	29.3739%	5.0036%	34.8016%	5.8857%	15.0280%	2.0190%	9.1097%	-2.5526%

See Calculation of EXCTAX

DITEXP:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
Pacific Power											
Production	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	S	0	0	0	0	0	0	0	0	0	0
Mining Plant	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 Pacific Power		0	0	0	0	0	0	0	0	0	0
Rocky Mountain Power											
Production	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	S	0	0	0	0	0	0	0	0	0	0
Mining Plant	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 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

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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
Percentage of Total (DITEXP)		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

DITBAL :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
Pacific Power											
Production	S	9,777,915	697,070	7,388,948	2,746,555	(3,240,319)	(149,348)	2,337,872	(2,863)	0	0
Transmission	S	8,964,074	351,488	4,959,478	1,365,447	303,754	(12,702)	1,996,680	(71)	0	0
Distribution	S	1,278,542	917,694	994,681	1,458,402	(2,185,933)	(6,120)	99,818	0	0	0
General	S	(748,972)	(5,380)	(278,915)	(19,951)	(302,365)	(14,904)	(127,251)	(206)	0	0
Mining Plant	S	4,407	67	1,103	336	1,870	274	749	8	0	0
Non Utility	NUTIL	(1,939,785)	0	0	0	0	0	0	0	0	(1,939,785)
Total Pacific Power		17,336,181	1,960,939	13,065,295	5,550,789	(5,422,993)	(182,800)	4,307,868	(3,132)	0	(1,939,785)
Rocky Mountain Power											
Production	S	18,611,188	(9,592)	(2,228,923)	(47,850)	17,745,620	3,059,945	(78,228)	170,216	0	0
Transmission	S	20,683,211	1,825	(100,528)	10,247	17,826,162	2,184,329	663,447	97,729	0	0
Distribution	S	18,593,410	263,279	1,661,579	517,101	13,212,021	1,742,856	1,196,574	0	0	0
General	S	(909,654)	(9,869)	(242,130)	(36,183)	(413,403)	(75,137)	(132,168)	(764)	0	0
Mining Plant	S	9,054	137	2,264	690	3,847	564	1,536	16	0	0
Non-Utility Plant	NUTIL	0	0	0	0	0	0	0	0	0	0
Total Rocky Mountain Power		56,987,209	245,780	(907,738)	444,005	48,374,247	6,912,557	1,651,161	267,197	0	0
PacifiCorp											
Prod / Other Prod	S	249,204,266	4,416,468	70,492,822	20,097,986	102,213,229	13,773,712	37,374,866	835,183	0	0
Cholla Unit 4	S	(23,473,392)	(420,509)	(6,755,315)	0	(10,252,543)	(1,493,615)	(3,559,253)	(62,043)	0	(930,114)
Gadsby Unit 4, 5 & 6	S	4,467,390	69,872	1,143,934	0	1,940,779	256,188	670,438	12,457	0	373,722
Hydro-PPL	S	21,982,344	426,497	6,524,494	1,845,885	8,716,933	1,155,368	3,242,695	70,472	0	0
Hydro-UPL	S	6,648,954	134,299	1,984,897	578,643	2,629,171	345,414	957,174	19,356	0	0
Transmission	S	178,123,314	3,241,193	51,872,161	14,499,795	72,076,958	9,589,293	26,294,460	549,454	0	0
Distribution	S	649,653,591	22,915,562	184,256,564	41,938,309	304,899,112	31,887,516	63,751,946	0	0	4,582
General/ Intangibles	S	17,901,804	441,815	6,029,398	1,274,868	6,458,219	993,470	2,653,270	50,763	0	1
Mining	S	2,017	30	506	154	864	129	333	1	0	0
WCA - CAEE 2007+	S	(2,206)	(5)	(503)	0	(814)	(133)	(354)	(1)	0	(396)

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WCA - CAGE 2007+	S	1,266,183,891	20,172,688	331,877,489	0	536,650,055	71,262,382	195,743,841	3,704,700	0	106,772,736
WCA - CAGW 2007+	S	297,854,804	4,850,882	80,671,915	64,830,916	128,365,959	17,126,528	46,695,258	872,634	0	(45,559,288)
WCA_CAGW 2007+ -Marengo	S	(43,905,412)	0	0	0	(43,905,412)	0	0	0	0	0
WCA CAGW 2007+ -Goodnoe	S	0	0	0	0	0	0	0	0	0	0
WCA - General 2007+	S	128,707,004	2,814,055	35,368,245	8,649,374	54,884,383	7,256,658	18,183,677	171,127	0	1,379,485
WCA - JBG 2007+	S	108,364,789	1,712,739	28,746,072	23,672,595	46,838,488	6,250,113	16,787,031	233,279	0	(15,875,528)
Oregon Extra Book Depreciation	S	(106,317,436)	0	(106,317,436)	0	0	0	0	0	0	0
Non Utility	NUTIL	(1,131,206)	0	0	0	0	0	0	0	0	(1,131,206)
Total PC (Post Merger)		2,754,264,516	60,775,586	685,895,243	177,388,525	1,211,515,381	158,403,023	408,795,382	6,457,382	0	45,033,994
Total Deferred Taxes		2,828,587,906	62,982,305	698,052,800	183,383,319	1,254,466,635	165,132,780	414,754,411	6,721,447	0	43,094,209
Percentage of Total (DITBAL)		100.0000%	2.2266%	24.6785%	6.4832%	44.3496%	5.8380%	14.6629%	0.2376%	0.0000%	1.5235%

OPRV-WY

	Pacific Division	Utah Division	Combined Total
Total Sales to Ultimate Customers	0	0	0
Less: Uncollectibles (net)	0	0	0
Total Interstate Revenues	0	0	0
	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
Total Interstate Revenues	0	0	0
	0.0000%	0.0000%	0.0000%

BADDEBT

	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	OTHER	Non-Utility
Account 904 Balance	14,195,691	771,457	5,062,459	1,760,886	4,794,271	757,522	1,049,097	0	0	0
Bad Debts Expense Allocation Factor - BADDEBT	100.0000%	5.4344%	35.6619%	12.4044%	33.7727%	5.3363%	7.3903%	0.0000%	0.0000%	0.0000%

Customer Factors	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility

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Total Electric Customers	1,984,793	47,567	619,594	137,667	949,235	83,405	147,325	0	0	0
CN										
Customer System factor - CN	107.4227%	2.3966%	31.2171%	6.9361%	47.8254%	4.2022%	7.4227%	0.0000%	0.0000%	0.0000%
Pacific Power Customers	935,782	47,567	619,594	137,667	0	0	130954	0	0	0
CNP										
Customer Service Pacific Power factor - CNP	100.0000%	5.0831%	66.2114%	14.7114%	0.0000%	0.0000%	13.9941%	0.0000%	0.0000%	0.0000%
Rocky Mountain Power Customers	1,049,011	0	0	0	949,235	83,405	16,371	0	0	0
CNU										
Customer Service R.M.P. factor - CNU	100.0000%	0.0000%	0.0000%	0.0000%	90.4886%	7.9508%	1.5606%	0.0000%	0.0000%	0.0000%

CIAC	**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
TOTAL NET DISTRIBUTION PLANT	4,559,247,474	165,212,726	1,219,889,583	280,277,048	2,194,458,734	232,756,911	466,652,471	0	0	0
CIAC FACTOR: Same as (SNPD Factor)	100.0000%	3.6237%	26.7564%	6.1474%	48.1320%	5.1052%	10.2353%	0.0000%	0.0000%	0.0000%

IDSIT		Total Company	Idaho - PPL	Idaho - UPL	Idaho Total
	Payroll	0	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%
	Average		0.00%	0.00%	
		Idaho - PPL Factor	0.00%	0.00%	
		Idaho - UPL Factor	0.00%	0.00%	
			0.00%	0.00%	

EXCTAX **Excise Tax (Superfund)**		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
Total Taxable Income		618,379,303	8,224,503	181,670,463	30,918,808	215,112,749	36,396,923	92,943,732	12,503,829	56,416,610	(15,808,315)
Less Other Electric Items:											
	419 OTH	0	0	0	0	0	0	0	0	0	0

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			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
	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			618,379,303	8,224,503	181,670,463	30,918,808	215,112,749	36,396,923	92,943,732	12,503,829	56,416,610	(15,808,315)
Excise Tax (Superfund) Factor - EXCTAX			100.0000%	1.3300%	29.3785%	5.0000%	34.7865%	5.8859%	15.0302%	2.0220%	9.1233%	-2.5564%

Trojan Allocators			**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
Premerger												
Dec 1991 Plant			16,918,976									
Dec 1992 Plant			17,094,202									
Average		SG	17,006,589	261,341	4,425,562	1,342,167	7,482,474	1,002,958	2,487,268	4,819	0	0
Dec 1991 Reserve			(7,851,432)									
Dec 1992 Reserve			(8,434,030)									
Average		SG	(8,142,731)	(125,130)	(2,118,953)	(642,627)	(3,582,598)	(480,215)	(1,190,900)	(2,308)	0	0
Postmerger												
Dec 1991 Plant			4,284,960									
Dec 1992 Plant			3,485,613									
Average		SG	3,885,287	59,705	1,011,054	306,628	1,709,429	229,134	568,236	1,101	0	0
Dec 1991 Reserve			(129,394)									
Dec 1992 Reserve			(240,609)									
Average		SG	(185,002)	(2,843)	(48,142)	(14,600)	(81,396)	(10,910)	(27,057)	(52)	0	0
Net Plant			12,564,143	193,073	3,269,521	991,567	5,527,909	740,967	1,837,546	3,561	0	0
Division Net Plant Nuclear Pacific Power		**DNPPNP**	100.0000%	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	0.0000%	0.0000%
Division Net Plant Nuclear Rocky Mountain Power		**DNPPNP**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
System Net Nuclear Plant		**SNNP**	100.0000%	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	0.0000%	0.0000%

Account 182.22			**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
Pre-merger	(101)	SG	17,094,202	262,687	4,448,361	1,349,081	7,521,021	1,008,125	2,500,082	4,844	0	0
		(108) SG	(8,434,030)	(129,606)	(2,194,757)	(665,617)	(3,710,762)	(497,394)	(1,233,504)	(2,390)	0	0
Post-merger	(101)	SG	3,485,613	53,563	907,048	275,086	1,533,583	205,563	509,782	988	0	0
		(108) SG	(240,609)	(3,697)	(62,613)	(18,989)	(105,862)	(14,190)	(35,190)	(68)	0	0
		(107) SG	1,778,549	27,331	462,825	140,364	782,517	104,889	260,118	504	0	0
		(120) SE	1,975,759	28,735	495,945	148,532	856,614	129,563	315,726	643	0	0
		(228) SG	7,220,849	110,963	1,879,055	569,872	3,176,993	425,847	1,056,072	2,046	0	0
		(228) SG	1,472,376	22,626	383,151	116,200	647,809	86,833	215,340	417	0	0
		(228) SNNP	3,531,000	54,261	918,859	278,668	1,553,552	208,240	516,420	1,001	0	0
		(228) SE	1,743,025	25,350	437,525	131,036	755,710	114,302	278,535	568	0	0
Total Acct 182.22			29,626,734	452,213	7,675,401	2,324,234	13,011,174	1,771,779	4,383,381	8,553	0	0
Revised Study	(228)	SNNP	112,680	1,732	29,322	8,893	49,576	6,645	16,480	32	0	0
		(228) SE	941,950	13,699	236,443	70,813	408,394	61,770	150,523	307	0	0
December 1993 Adj.			1,054,630	15,431	265,766	79,706	457,970	68,415	167,003	339	0	0

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		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Adjusted Acct 182.22		30,681,364	467,644	7,941,167	2,403,940	13,469,144	1,840,194	4,550,384	8,892	0	0
TROJP		100.0000%	1.5242%	25.8827%	7.8352%	43.9001%	5.9978%	14.8311%	0.0290%	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	110,963	1,879,055	569,872	3,176,993	425,847	1,056,072	2,046	0	0
- Postmerger	SG	1,472,376	22,626	383,151	116,200	647,809	86,833	215,340	417	0	0
Storage Facility	SE	1,743,025	25,350	437,525	131,036	755,710	114,302	278,535	568	0	0
Transition Costs	SNNP	3,531,000	54,261	918,859	278,668	1,553,552	208,240	516,420	1,001	0	0
Total Acct 228.42		13,967,250	213,200	3,618,590	1,095,777	6,134,063	835,222	2,066,367	4,032	0	0
Transition Costs	SNNP	112,680	1,732	29,322	8,893	49,576	6,645	16,480	32	0	0
Storage Facility	SE	941,950	13,699	236,443	70,813	408,394	61,770	150,523	307	0	0
December 1993 Adj.		1,054,630	15,431	265,766	79,706	457,970	68,415	167,003	339	0	0
Adjusted Acct 228.42		15,021,880	228,631	3,884,356	1,175,483	6,592,033	903,637	2,233,370	4,371	0	0
TROJD		100.0000%	1.5220%	25.8580%	7.8251%	43.8829%	6.0155%	14.8674%	0.0291%	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	39,770,069	829,688	11,003,177	2,978,088	13,793,597	2,079,283	4,827,554	6,521	4,252,162	0
Amortization of Other Electric Plant	Acct 405	0	0	0	0	0	0	0	0	0	0
Amortization of Plant Acquisitions	Acct 406	5,083,195	73,478	1,244,288	377,363	2,405,402	281,991	699,318	1,355	0	0
Amort of Prop. Losses, Unrecovered Plant, etc.	Acct 407	39,218,681	628,352	8,844,354	3,227,991	17,990,413	2,411,453	5,980,239	11,588	124,290	0
Total Amortization Expense :		84,071,945	1,531,518	21,091,819	6,583,441	34,189,412	4,772,727	11,507,111	19,463	4,376,453	0
Schedule M Amortization Factor		100.0000%	1.8217%	25.0878%	7.8307%	40.6669%	5.6770%	13.6872%	0.0232%	5.2056%	0.0000%

SCHMD		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Depreciation Expense :											
Steam	Acct 403.1	529,193,763	8,132,132	137,710,149	41,764,178	232,832,016	31,209,042	77,396,279	149,968	0	0
Nuclear	Acct 403.2	0	0	0	0	0	0	0	0	0	0
Hydro	Acct 403.3	31,196,075	479,391	8,118,040	2,462,006	13,725,493	1,839,779	4,562,526	8,841	0	0
Other	Acct 403.4	234,123,484	3,597,689	60,929,531	18,476,643	103,005,837	13,807,008	34,240,430	66,347	0	0
Transmission	Acct 403.5	141,875,879	2,180,210	36,919,839	11,196,900	62,421,837	8,367,087	20,749,801	40,206	0	0
Distribution	Acct 403.6	201,425,242	8,373,979	59,215,689	15,101,449	85,711,083	10,272,310	22,750,732	0	0	0
General	Acct 403.7&8	46,657,902	1,113,740	13,666,937	3,426,137	18,968,067	2,775,643	6,700,746	6,632	0	0
Mining	Acct 403.9	0	0	0	0	0	0	0	0	0	0
Experimental	Acct 403.4	0	0	0	0	0	0	0	0	0	0
Total Depreciation Expense :		1,184,472,345	23,877,140	316,560,184	92,427,312	516,664,333	68,270,868	166,400,514	271,993	0	0
Schedule M Depreciation Factor		100.0000%	2.0158%	26.7258%	7.8032%	43.6198%	5.7638%	14.0485%	0.0230%	0.0000%	0.0000%

Tax Depreciation by Function		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2021

Based on Tax Depreciation Schedule M Differences	970,347,616	18,804,463	254,945,162	56,479,728	434,428,196	55,354,251	133,045,780	213,286	-	17,076,750
Tax Depr factor	100.0000%	1.9379%	26.2736%	5.8206%	44.7704%	5.7046%	13.7111%	0.0220%	0.0000%	1.7599%

Pro Forma Factors December 31, 2021
Oregon General Rate Case - December 2021
COINCIDENTAL PEAKS

FORECAST LOADS (CP)

			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-21	14	8	158	2,638	840	3,407	452	1,274	35	8,803
Feb-21	9	8	148	2,448	701	3,284	433	1,235	34	8,281
Mar-21	11	8	143	2,364	670	3,187	429	1,205	34	8,031
Apr-21	7	8	125	2,225	582	3,024	419	1,143	35	7,554
May-21	18	15	116	1,914	575	3,807	527	1,145	34	8,118
Jun-21	24	15	133	2,051	684	4,673	712	1,244	34	9,531
Jul-21	19	16	144	2,376	755	4,911	794	1,270	36	10,286
Aug-21	26	16	136	2,449	746	4,764	613	1,221	35	9,963
Sep-21	9	16	121	2,138	660	4,326	514	1,144	35	8,938
Oct-21	4	18	110	1,890	602	3,586	418	1,153	35	7,793
Nov-21	24	18	131	2,206	704	3,554	454	1,258	37	8,343
Dec-21	15	18	145	2,402	734	3,746	476	1,300	35	8,838
			1,610	27,103	8,252	46,269	6,239	14,590	418	104,481

- (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-21	14	8	-	-	-	115	-	-	33	148
Feb-21	9	8	-	-	-	23	-	-	32	55
Mar-21	11	8	-	-	-	25	-	-	32	56
Apr-21	7	8	-	-	-	26	-	-	33	58
May-21	18	15	-	-	-	28	-	-	32	60
Jun-21	24	15	-	-	-	254	170	-	32	456
Jul-21	19	16	-	-	-	241	146	-	33	419
Aug-21	26	16	-	-	-	253	79	-	32	364
Sep-21	9	16	-	-	-	95	-	-	32	127
Oct-21	4	18	-	-	-	-	-	-	33	33
Nov-21	24	18	-	-	-	-	-	-	35	35
Dec-21	15	18	-	-	-	91	-	-	32	123
			-	-	-	1,150	395	-	390	1,935

= equals

COINCIDENTAL PEAK SERVED FROM COMPANY RESOURCES

			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-21	14	8	158	2,638	840	3,291	452	1,274	2	8,656
Feb-21	9	8	148	2,448	701	3,261	433	1,235	2	8,226
Mar-21	11	8	143	2,364	670	3,162	429	1,205	2	7,975
Apr-21	7	8	125	2,225	582	2,999	419	1,143	2	7,496
May-21	18	15	116	1,914	575	3,780	527	1,145	2	8,058
Jun-21	24	15	133	2,051	684	4,419	542	1,244	2	9,075
Jul-21	19	16	144	2,376	755	4,671	648	1,270	3	9,866
Aug-21	26	16	136	2,449	746	4,511	534	1,221	3	9,599
Sep-21	9	16	121	2,138	660	4,231	514	1,144	2	8,810
Oct-21	4	18	110	1,890	602	3,586	418	1,153	2	7,760
Nov-21	24	18	131	2,206	704	3,554	454	1,258	2	8,309
Dec-21	15	18	145	2,402	734	3,656	476	1,300	3	8,715
			1,610	27,103	8,252	45,119	5,844	14,590	28	102,546

+ 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-21	14	8	-	-	-	33	-	-	-	33
Feb-21	9	8	-	-	-	32	-	-	-	32
Mar-21	11	8	-	-	-	32	-	-	-	32
Apr-21	7	8	-	-	-	33	-	-	-	33
May-21	18	15	-	-	-	32	-	-	-	32
Jun-21	24	15	-	-	-	32	-	-	-	32
Jul-21	19	16	-	-	-	33	-	-	-	33
Aug-21	26	16	-	-	-	32	-	-	-	32
Sep-21	9	16	-	-	-	32	-	-	-	32
Oct-21	4	18	-	-	-	33	-	-	-	33
Nov-21	24	18	-	-	-	35	-	-	-	35
Dec-21	15	18	-	-	-	32	-	-	-	32
			-	-	-	390	-	-	-	390

= equals

LOADS FOR JURISDICTIONAL ALLOCATION (CP)

			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-21	14	8	158	2,638	840	3,324	452	1,274	2	8,688
Feb-21	9	8	148	2,448	701	3,293	433	1,235	2	8,258
Mar-21	11	8	143	2,364	670	3,194	429	1,205	2	8,006
Apr-21	7	8	125	2,225	582	3,031	419	1,143	2	7,529
May-21	18	15	116	1,914	575	3,812	527	1,145	2	8,091
Jun-21	24	15	133	2,051	684	4,451	542	1,244	2	9,107
Jul-21	19	16	144	2,376	755	4,703	648	1,270	3	9,899
Aug-21	26	16	136	2,449	746	4,543	534	1,221	3	9,631
Sep-21	9	16	121	2,138	660	4,263	514	1,144	2	8,843
Oct-21	4	18	110	1,890	602	3,619	418	1,153	2	7,793
Nov-21	24	18	131	2,206	704	3,588	454	1,258	2	8,343
Dec-21	15	18	145	2,402	734	3,688	476	1,300	3	8,747
			1,610	27,103	8,252	45,509	5,844	14,590	28	102,936

Pro Forma Factors December 31, 2021
Oregon General Rate Case - December 2021
ENERGY

		FORECAST LOADS (MWh)							
		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2021	Jan	80,880	1,445,050	443,650	2,215,100	303,070	875,880	25,454	5,389,084
2021	Feb	68,410	1,246,380	371,420	1,938,450	263,240	786,720	22,855	4,697,475
2021	Mar	70,110	1,295,980	365,150	2,034,680	292,240	827,140	24,573	4,909,873
2021	Apr	67,640	1,191,840	332,720	1,956,860	284,450	778,150	24,466	4,636,126
2021	May	73,560	1,182,260	341,350	2,039,760	342,760	789,460	24,952	4,794,102
2021	Jun	77,460	1,171,530	347,030	2,281,780	402,830	777,680	24,663	5,082,973
2021	Jul	83,620	1,308,420	401,760	2,698,330	490,400	829,390	24,758	5,836,678
2021	Aug	79,230	1,289,920	397,670	2,594,840	402,350	820,020	24,754	5,608,784
2021	Sep	68,350	1,162,130	356,060	2,175,030	314,430	768,290	24,290	4,868,580
2021	Oct	64,420	1,183,660	364,900	2,068,640	286,680	798,380	25,656	4,792,336
2021	Nov	68,130	1,279,230	389,850	2,051,690	286,810	793,990	25,244	4,894,944
2021	Dec	80,020	1,463,450	446,690	2,233,500	306,860	844,080	25,973	5,400,573
		881,830	15,219,850	4,558,250	26,288,660	3,976,120	9,689,180	297,637	60,911,527

- (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
2021	Jan				19,953		-	23,708	43,660
2021	Feb				13,658		-	21,354	35,011
2021	Mar				21,443		-	23,004	44,447
2021	Apr				23,649		-	23,052	46,701
2021	May				27,259		-	23,493	50,752
2021	Jun				28,383		-	23,002	51,385
2021	Jul				32,194		-	22,769	54,963
2021	Aug				30,572		-	22,867	53,439
2021	Sep				31,295		-	22,756	54,051
2021	Oct				19,304		-	24,222	43,526
2021	Nov				13,605		-	23,610	37,215
2021	Dec				16,955		-	24,055	41,009
		-	-	-	278,269	-	-	277,891	556,160

= equals

		LOADS SERVED FROM COMPANY RESOURCES (NPC)							
		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2021	Jan	80,880	1,445,050	443,650	2,195,147	303,070	875,880	1,746	5,345,424
2021	Feb	68,410	1,246,380	371,420	1,924,792	263,240	786,720	1,502	4,662,464
2021	Mar	70,110	1,295,980	365,150	2,013,237	292,240	827,140	1,568	4,865,426
2021	Apr	67,640	1,191,840	332,720	1,933,211	284,450	778,150	1,414	4,589,425
2021	May	73,560	1,182,260	341,350	2,012,501	342,760	789,460	1,458	4,743,350
2021	Jun	77,460	1,171,530	347,030	2,253,397	402,830	777,680	1,661	5,031,588
2021	Jul	83,620	1,308,420	401,760	2,666,136	490,400	829,390	1,989	5,781,715
2021	Aug	79,230	1,289,920	397,670	2,564,268	402,350	820,020	1,887	5,555,345
2021	Sep	68,350	1,162,130	356,060	2,143,735	314,430	768,290	1,533	4,814,528
2021	Oct	64,420	1,183,660	364,900	2,049,336	286,680	798,380	1,434	4,748,810
2021	Nov	68,130	1,279,230	389,850	2,038,085	286,810	793,990	1,634	4,857,729
2021	Dec	80,020	1,463,450	446,690	2,216,545	306,860	844,080	1,918	5,359,564
		881,830	15,219,850	4,558,250	26,010,391	3,976,120	9,689,180	19,746	60,355,367

+ plus

		Add: Resolute NTUA (UT) - Grossed up for Line Losses							
		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2021	Jan				23,708		-		23,708
2021	Feb				21,354		-		21,354
2021	Mar				23,004		-		23,004
2021	Apr				23,052		-		23,052
2021	May				23,493		-		23,493
2021	Jun				23,002		-		23,002
2021	Jul				22,769		-		22,769
2021	Aug				22,867		-		22,867
2021	Sep				22,756		-		22,756
2021	Oct				24,222		-		24,222
2021	Nov				23,610		-		23,610
2021	Dec				24,055		-		24,055
		-	-	-	277,891	-	-	-	277,891

= equals

		LOADS FOR JURISDICTIONAL ALLOCATION (MWh)							
		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2021	Jan	80,880	1,445,050	443,650	2,218,855	303,070	875,880	1,746	5,369,131
2021	Feb	68,410	1,246,380	371,420	1,946,146	263,240	786,720	1,502	4,683,818
2021	Mar	70,110	1,295,980	365,150	2,036,242	292,240	827,140	1,568	4,888,430
2021	Apr	67,640	1,191,840	332,720	1,956,263	284,450	778,150	1,414	4,612,477
2021	May	73,560	1,182,260	341,350	2,035,995	342,760	789,460	1,458	4,766,843
2021	Jun	77,460	1,171,530	347,030	2,276,400	402,830	777,680	1,661	5,054,590
2021	Jul	83,620	1,308,420	401,760	2,688,904	490,400	829,390	1,989	5,804,483
2021	Aug	79,230	1,289,920	397,670	2,587,135	402,350	820,020	1,887	5,578,211
2021	Sep	68,350	1,162,130	356,060	2,166,491	314,430	768,290	1,533	4,837,284
2021	Oct	64,420	1,183,660	364,900	2,073,558	286,680	798,380	1,434	4,773,032
2021	Nov	68,130	1,279,230	389,850	2,061,695	286,810	793,990	1,634	4,881,339
2021	Dec	80,020	1,463,450	446,690	2,240,600	306,860	844,080	1,918	5,383,619
		881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258

Pro Forma Factors December 31, 2021
Oregon General Rate Case - December 2021

	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC		
Subtotal	881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	**60,633,258**	**Ref Page 10.15**
System Energy Factor	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	100.00%	
Divisional Energy - Pacific	3.0995%	53.4958%	16.0217%	0.0000%	0.0000%	27.3830%	0.0000%	100.00%	
Divisional Energy - Utah	0.0000%	0.0000%	0.0000%	81.6845%	12.3548%	5.8993%	0.0614%	100.00%	
System Generation Factor	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	100.00%	
Divisional Generation - Pacific	3.2512%	55.0569%	16.6974%	0.0000%	0.0000%	24.9944%	0.0000%	100.00%	
Divisional Generation - Utah	0.0000%	0.0000%	0.0000%	83.4313%	11.1832%	5.3318%	0.0537%	100.00%	
System Capacity (kw)									
Accord	1,610.1	27,102.6	8,252.2	45,509.1	5,844.1	14,589.9	27.7	**102,936**	**Ref Page 10.14**
Modified Accord	1,610.1	27,102.6	8,252.2	45,509.1	5,844.1	14,589.9	27.7	**102,936**	**Ref Page 10.14**
Rolled-In	1,610.1	27,102.6	8,252.2	45,509.1	5,844.1	14,589.9	27.7	**102,936**	**Ref Page 10.14**
Rolled-In with Hydro Adj.	1,610.1	27,102.6	8,252.2	45,509.1	5,844.1	14,589.9	27.7	**102,936**	**Ref Page 10.14**
Rolled-In with Off-Sys Adj.	1,610.1	27,102.6	8,252.2	45,509.1	5,844.1	14,589.9	27.7	**102,936**	**Ref Page 10.14**
System Capacity Factor									
Accord	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%	100.00%	
Modified Accord	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%	100.00%	
Rolled-In	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%	100.00%	
Rolled-In with Hydro Adj.	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%	100.00%	
Rolled-In with Off-Sys Adj.	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%	100.00%	
System Energy (kwh)									
Accord	881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258	
Modified Accord	881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258	
Rolled-In	881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258	
Rolled-In with Hydro Adj.	881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258	
Rolled-In with Off-Sys Adj.	881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258	
System Energy Factor									
Accord	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	100.00%	
Modified Accord	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	100.00%	
Rolled-In	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	100.00%	
Rolled-In with Hydro Adj.	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	100.00%	
Rolled-In with Off-Sys Adj.	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	100.00%	
System Generation Factor									
Accord	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	100.00%	
Modified Accord	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	100.00%	
Rolled-In	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	100.00%	
Rolled-In with Hydro Adj.	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	100.00%	
Rolled-In with Off-Sys Adj.	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	100.00%	

PACIFICORP

Electric Operations Revenue
Twelve Months Ending - June 2019
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	-46,710	-46,710	0	0	0	0	0	0	0
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	IDU	-77,265	0	0	0	0	0	-77,265	0	0
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	OR	-641,470	0	-641,470	0	0	0	0	0	0
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	UT	-760,615	0	0	0	0	-760,615	0	0	0
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WA	-151,545	0	0	-151,545	0	0	0	0	0
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WYP	-96,240	0	0	0	-96,240	0	0	0	0
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WYU	-12,534	0	0	0	-12,534	0	0	0	0
4401000	RESIDENTIAL SALES	301106	Residential-Alt Revenue Program Adjs	WA	-1,597	0	0	-1,597	0	0	0	0	0
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	CA	676	676	0	0	0	0	0	0	0
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	IDU	251	0	0	0	0	0	251	0	0
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	OR	3,147	0	3,147	0	0	0	0	0	0
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	UT	1,135	0	0	0	0	1,135	0	0	0
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	WA	8,932	0	0	8,932	0	0	0	0	0
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	WYP	-188	0	0	0	-188	0	0	0	0
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	UT	-1,652	0	0	0	0	-1,652	0	0	0
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	WA	-63	0	0	-63	0	0	0	0	0
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	WYP	32	0	0	0	32	0	0	0	0
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	CA	-1,352	-1,352	0	0	0	0	0	0	0
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	IDU	-817	0	0	0	0	0	-817	0	0
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	OR	502	0	502	0	0	0	0	0	0
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	UT	5,678	0	0	0	0	5,678	0	0	0
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WA	-606	0	0	-606	0	0	0	0	0
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WYP	523	0	0	0	523	0	0	0	0
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WYU	153	0	0	0	153	0	0	0	0
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	CA	1,319	1,319	0	0	0	0	0	0	0
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	IDU	-207	0	0	0	0	0	-207	0	0
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	OR	8,532	0	8,532	0	0	0	0	0	0
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	UT	-8,336	0	0	0	0	-8,336	0	0	0
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	WA	-102	0	0	-102	0	0	0	0	0
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	WYP	-1,119	0	0	0	-1,119	0	0	0	0
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	CA	7	7	0	0	0	0	0	0	0
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	IDU	6	0	0	0	0	0	6	0	0
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	OR	17	0	17	0	0	0	0	0	0
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	UT	-37	0	0	0	0	-37	0	0	0
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	WA	16	0	0	16	0	0	0	0	0
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	WYP	15	0	0	0	15	0	0	0	0
4401000	RESIDENTIAL SALES	301165	Solar Feed-In Revenue - Residential	OTHER	-3,485	0	0	0	0	0	0	0	-3,485
4401000	RESIDENTIAL SALES	301170	DSM Revenue - Residential	OTHER	-31,369	0	0	0	0	0	0	0	-31,369
4401000	RESIDENTIAL SALES	301171	DSM Revenue - Residential Cat 2 Gen Svc	OTHER	-48	0	0	0	0	0	0	0	-48
4401000	RESIDENTIAL SALES	301180	Blue Sky Revenue Residential	OTHER	-2,390	0	0	0	0	0	0	0	-2,390
4401000 Total					**-1,808,805**	**-46,059**	**-629,272**	**-144,965**	**-109,358**	**-763,827**	**-78,031**	**0**	**-37,292**
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	CA	-35,247	-35,247	0	0	0	0	0	0	0
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	IDU	-43,418	0	0	0	0	0	-43,418	0	0
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	OR	-486,477	0	-486,477	0	0	0	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	UT	-726,297	0	0	0	0	-726,297	0	0	0
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WA	-129,042	0	0	-129,042	0	0	0	0	0
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WYP	-105,219	0	0	0	-105,219	0	0	0	0
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WYU	-10,838	0	0	0	-10,838	0	0	0	0
4421000	COMMERCIAL SALES	301206	Commercial-Alt Revenue Program Adjs	WA	967	0	0	967	0	0	0	0	0
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	CA	473	473	0	0	0	0	0	0	0
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	IDU	144	0	0	0	0	0	144	0	0
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	OR	1,012	0	1,012	0	0	0	0	0	0
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	UT	760	0	0	0	0	760	0	0	0
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	WA	9,069	0	0	9,069	0	0	0	0	0
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	WYP	-238	0	0	0	-238	0	0	0	0
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	UT	-2,134	0	0	0	0	-2,134	0	0	0
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	WA	-60	0	0	-60	0	0	0	0	0
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	WYP	44	0	0	0	44	0	0	0	0
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	CA	-31	-31	0	0	0	0	0	0	0
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	IDU	-37	0	0	0	0	0	-37	0	0
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	OR	1,789	0	1,789	0	0	0	0	0	0
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	UT	-1,795	0	0	0	0	-1,795	0	0	0
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WA	-1,694	0	0	-1,694	0	0	0	0	0
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WYP	-2,558	0	0	0	-2,558	0	0	0	0
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WYU	-64	0	0	0	-64	0	0	0	0
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	CA	825	825	0	0	0	0	0	0	0
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	IDU	-146	0	0	0	0	0	-146	0	0
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	OR	7,860	0	7,860	0	0	0	0	0	0
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	UT	-10,849	0	0	0	0	-10,849	0	0	0
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	WA	-93	0	0	-93	0	0	0	0	0
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	WYP	-1,519	0	0	0	-1,519	0	0	0	0
4421000	COMMERCIAL SALES	301265	Solar Feed-In Revenue - Commercial	OTHER	-3,708	0	0	0	0	0	0	0	-3,708
4421000	COMMERCIAL SALES	301270	DSM Revenue - Commercial	OTHER	-22,164	0	0	0	0	0	0	0	-22,164
4421000	COMMERCIAL SALES	301271	DSM Revenue - Small Commercial	OTHER	-3,864	0	0	0	0	0	0	0	-3,864
4421000	COMMERCIAL SALES	301272	DSM Revenue - Large Commercial	OTHER	-25	0	0	0	0	0	0	0	-25
4421000	COMMERCIAL SALES	301280	Blue Sky Revenue - Commercial	OTHER	-1,039	0	0	0	0	0	0	0	-1,039
4421000 Total					**-1,565,613**	**-33,981**	**-475,816**	**-120,853**	**-120,392**	**-740,315**	**-43,457**	**0**	**-30,800**
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	CA	-6,696	-6,696	0	0	0	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	IDU	-13,359	0	0	0	0	0	-13,359	0	0
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	OR	-123,492	0	-123,492	0	0	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	UT	-343,532	0	0	0	0	-343,532	0	0	0
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WA	-49,538	0	0	-49,538	0	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WYP	-338,278	0	0	0	-338,278	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WYU	-94,279	0	0	0	-94,279	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301304	SPECIAL CONTRACTS-SITUS	IDU	-95,658	0	0	0	0	0	-95,658	0	0
4422000	IND SLS/EXCL IRRIG	301304	SPECIAL CONTRACTS-SITUS	UT	-143,121	0	0	0	0	-143,121	0	0	0
4422000	IND SLS/EXCL IRRIG	301306	Industrial-Alt Revenue Program Adjs	WA	1,436	0	0	1,436	0	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	CA	67	67	0	0	0	0	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	IDU	-18	0	0	0	0	0	-18	0	0
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	OR	1,414	0	1,414	0	0	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	UT	141	0	0	0	0	141	0	0	0
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	WA	3,523	0	0	3,523	0	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	WYP	-1,060	0	0	0	-1,060	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	UT	-1,911	0	0	0	0	-1,911	0	0	0
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	WA	-29	0	0	-29	0	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	WYP	217	0	0	0	217	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	CA	68	68	0	0	0	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	IDU	212	0	0	0	0	0	212	0	0
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	OR	2,873	0	2,873	0	0	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	UT	19,800	0	0	0	0	19,800	0	0	0
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WA	-301	0	0	-301	0	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WYP	798	0	0	0	798	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WYU	-60	0	0	0	-60	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	CA	203	203	0	0	0	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	IDU	-523	0	0	0	0	0	-523	0	0
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	OR	2,757	0	2,757	0	0	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	UT	-10,026	0	0	0	0	-10,026	0	0	0
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	WA	-49	0	0	-49	0	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	WYP	-7,427	0	0	0	-7,427	0	0	0	0
4422000	IND SLS/EXCL IRRIG	301365	Solar Feed-In Revenue - Industrial	OTHER	-2,631	0	0	0	0	0	0	0	-2,631
4422000	IND SLS/EXCL IRRIG	301370	DSM Revenue - Industrial	OTHER	-6,475	0	0	0	0	0	0	0	-6,475
4422000	IND SLS/EXCL IRRIG	301371	DSM Revenue - Small Industrial	OTHER	-1,008	0	0	0	0	0	0	0	-1,008
4422000	IND SLS/EXCL IRRIG	301372	DSM Revenue - Large Industrial	OTHER	-871	0	0	0	0	0	0	0	-871
4422000	IND SLS/EXCL IRRIG	301380	Blue Sky Revenue - Industrial	OTHER	-515	0	0	0	0	0	0	0	-515
4422000 Total					**-1,207,347**	**-6,358**	**-116,448**	**-44,958**	**-440,089**	**-478,648**	**-109,346**	**0**	**-11,500**
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	CA	-12,870	-12,870	0	0	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	IDU	-53,649	0	0	0	0	0	-53,649	0	0
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	OR	-30,337	0	-30,337	0	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	UT	-17,697	0	0	0	0	-17,697	0	0	0
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WA	-14,966	0	0	-14,966	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WYP	-1,612	0	0	0	-1,612	0	0	0	0
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WYU	-487	0	0	0	-487	0	0	0	0
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	CA	300	300	0	0	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	IDU	-160	0	0	0	0	0	-160	0	0
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	OR	457	0	457	0	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	UT	-276	0	0	0	0	-276	0	0	0
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	WA	-9	0	0	-9	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	WYP	-28	0	0	0	-28	0	0	0	0
4423000	INDUST SALES-IRRIG	301456	Irrigation-Alt Revenue Program Adjs	WA	658	0	0	658	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	CA	254	254	0	0	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	IDU	179	0	0	0	0	0	179	0	0
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	OR	113	0	113	0	0	0	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	UT	7	0	0	0	0	7	0	0	0
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	WA	1,087	0	0	1,087	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	WYP	-2	0	0	0	-2	0	0	0	0
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	UT	-60	0	0	0	0	-60	0	0	0
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	WA	-6	0	0	-6	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	WYP	1	0	0	0	1	0	0	0	0
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	CA	-396	-396	0	0	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	IDU	1,265	0	0	0	0	0	1,265	0	0
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	OR	-5,262	0	-5,262	0	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	UT	-494	0	0	0	0	-494	0	0	0
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WA	-1,173	0	0	-1,173	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WYP	11	0	0	0	11	0	0	0	0
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WYU	-29	0	0	0	-29	0	0	0	0
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Charg	CA	-37	-37	0	0	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Charg	OR	8	0	8	0	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Charg	WA	-122	0	0	-122	0	0	0	0	0
4423000	INDUST SALES-IRRIG	301465	Solar Feed-In Revenue - Irrigation	OTHER	-130	0	0	0	0	0	0	0	-130
4423000	INDUST SALES-IRRIG	301470	DSM Revenue - Irrigation	OTHER	-3,167	0	0	0	0	0	0	0	-3,167
4423000	INDUST SALES-IRRIG	301480	Blue Sky Revenue - Irrigation	OTHER	-1	0	0	0	0	0	0	0	-1
4423000 Total					**-138,632**	**-12,749**	**-35,022**	**-14,531**	**-2,146**	**-18,521**	**-52,366**	**0**	**-3,298**
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	CA	-418	-418	0	0	0	0	0	0	0
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	IDU	-514	0	0	0	0	0	-514	0	0
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	OR	-6,336	0	-6,336	0	0	0	0	0	0
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	UT	-7,840	0	0	0	0	-7,840	0	0	0
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WA	-1,280	0	0	-1,280	0	0	0	0	0
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WYP	-1,599	0	0	0	-1,599	0	0	0	0
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WYU	-340	0	0	0	-340	0	0	0	0
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	CA	8	8	0	0	0	0	0	0	0
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	IDU	3	0	0	0	0	0	3	0	0
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	OR	16	0	16	0	0	0	0	0	0
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	UT	19	0	0	0	0	19	0	0	0
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	WA	58	0	0	58	0	0	0	0	0
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	WYU	-4	0	0	0	-4	0	0	0	0
4441000	PUB ST/HWY LIGHT	301608	Public St/Hwy Lgt Rev Adj-Def NPC Mech	UT	-17	0	0	0	0	-17	0	0	0
4441000	PUB ST/HWY LIGHT	301608	Public St/Hwy Lgt Rev Adj-Def NPC Mech	WYP	0	0	0	0	0	0	0	0	0
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	CA	52	52	0	0	0	0	0	0	0
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	IDU	-10	0	0	0	0	0	-10	0	0
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	OR	291	0	291	0	0	0	0	0	0
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	UT	-104	0	0	0	0	-104	0	0	0
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WA	-20	0	0	-20	0	0	0	0	0
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WYP	40	0	0	0	40	0	0	0	0
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WYU	-6	0	0	0	-6	0	0	0	0
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	CA	6	6	0	0	0	0	0	0	0
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	IDU	-1	0	0	0	0	0	-1	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	OR	60	0	60	0	0	0	0	0	0
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	UT	-92	0	0	0	0	-92	0	0	0
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	WA	-1	0	0	-1	0	0	0	0	0
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	WYP	-14	0	0	0	-14	0	0	0	0
4441000	PUB ST/HWY LIGHT	301665	Solar Feed-In Revenue - St/Hwy Lighting	OTHER	-27	0	0	0	0	0	0	0	-27
4441000	PUB ST/HWY LIGHT	301670	DSM Revenue - Street/Hwy Lighting	OTHER	-336	0	0	0	0	0	0	0	-336
4441000 Total					**-18,405**	**-352**	**-5,969**	**-1,243**	**-1,922**	**-8,033**	**-522**	**0**	**-363**
4471000	ON-SYS WHOLE-FIRM	301443	ON SYS FIRM-UTAH FERC CUSTOMERS	FERC	-14,080	0	0	0	0	0	0	-14,080	0
4471000	ON-SYS WHOLE-FIRM	301445	On Sys Firm-Utah W/S Customers-Deferral	UT	79	0	0	0	0	79	0	0	0
4471000 Total					**-14,002**	**0**	**0**	**0**	**0**	**79**	**0**	**-14,080**	**0**
4471300	POST MERGER FIRM	301405	POST MERGER FIRM	SG	-14,223	-219	-3,701	-1,122	-2,080	-6,258	-839	-4	0
4471300 Total					**-14,223**	**-219**	**-3,701**	**-1,122**	**-2,080**	**-6,258**	**-839**	**-4**	**0**
4471400	S/T FIRM WHOLESALE	301406	SHORT-TERM FIRM WHOLESALE SALES	SG	-456,952	-7,022	-118,911	-36,063	-66,831	-201,048	-26,949	-129	0
4471400	S/T FIRM WHOLESALE	301409	TRADING SALES NETTED-EST.	SG	-123	-2	-32	-10	-18	-54	-7	0	0
4471400	S/T FIRM WHOLESALE	301410	TRADING SALES NETTED	SG	3,401	52	885	268	497	1,496	201	1	0
4471400	S/T FIRM WHOLESALE	301411	BOOKOUT SALES NETTED	SG	251,637	3,867	65,482	19,859	36,803	110,714	14,840	71	0
4471400	S/T FIRM WHOLESALE	301412	BOOKOUT SALES NETTED-ESTIMATE	SG	-6,478	-100	-1,686	-511	-947	-2,850	-382	-2	0
4471400	S/T FIRM WHOLESALE	302751	I/C S-T Firm Wholesale Sales-Sierra Pac	SG	-6	0	-2	0	-1	-3	0	0	0
4471400	S/T FIRM WHOLESALE	302752	I/C S-T Firm Wholesale Sales-Nevada Pwr	SG	-326	-5	-85	-26	-48	-143	-19	0	0
4471400	S/T FIRM WHOLESALE	302772	I/C Line Loss Trading Revenue-Nevada Pwr	SG	-19	0	-5	-2	-3	-9	-1	0	0
4471400	S/T FIRM WHOLESALE	303028	LINE LOSS W/S TRADING REVENUES	SG	-8,433	-130	-2,194	-666	-1,233	-3,710	-497	-2	0
4471400 Total					**-217,300**	**-3,339**	**-56,547**	**-17,149**	**-31,781**	**-95,607**	**-12,815**	**-62**	**0**
4472000	SLS FOR RESL-SURP	301419	ESTIMATED SALES FOR RESALE REVENUE	SG	14,185	218	3,691	1,119	2,075	6,241	837	4	0
4472000	SLS FOR RESL-SURP	302762	I/C Wholesale Sales Estimate-Nevada Pwr	SG	29	0	8	2	4	13	2	0	0
4472000	SLS FOR RESL-SURP	303198	Non-ASC 606-WS NPC Rev-Derivativ (Disc)	SG	-65,320	-1,004	-16,998	-5,155	-9,553	-28,739	-3,852	-19	0
4472000	SLS FOR RESL-SURP	303199	Non-ASC 606-WS NPC Rev-Derivativ (Recl)	SG	65,320	1,004	16,998	5,155	9,553	28,739	3,852	19	0
4472000 Total					**14,214**	**218**	**3,699**	**1,122**	**2,079**	**6,254**	**838**	**4**	**0**
4475000	OFF-SYS - NON FIRM	301408	OFF-SYSTEM WHOLESALE - NON FIRM	SE	1	0	0	0	0	0	0	0	0
4475000 Total					**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4476100	BOOKOUTS NETTED-GAIN	304101	BOOKOUTS NETTED-GAIN	SG	-8,336	-128	-2,169	-658	-1,219	-3,668	-492	-2	0
4476100	BOOKOUTS NETTED-GAIN	304102	BOOKOUTS NETTED-EST GAIN	SG	-3,899	-60	-1,015	-308	-570	-1,716	-230	-1	0
4476100 Total					**-12,236**	**-188**	**-3,184**	**-966**	**-1,790**	**-5,383**	**-722**	**-3**	**0**
4476200	TRADING NETTED-GAINS	304201	TRADING NETTED-GAINS	SG	-305	-5	-79	-24	-45	-134	-18	0	0
4476200 Total					**-305**	**-5**	**-79**	**-24**	**-45**	**-134**	**-18**	**0**	**0**
4479000	TRANS SRVC	301428	TRANS SERV-UTAH FERC CUSTOMERS	FERC	-83	0	0	0	0	0	0	-83	0
4479000 Total					**-83**	**0**	**0**	**0**	**0**	**0**	**0**	**-83**	**0**
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	CA	-183	-183	0	0	0	0	0	0	0
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	IDU	-210	0	0	0	0	0	-210	0	0
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	OR	-3,121	0	-3,121	0	0	0	0	0	0
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	UT	-2,387	0	0	0	0	-2,387	0	0	0
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WA	-563	0	0	-563	0	0	0	0	0
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WYP	-407	0	0	0	-407	0	0	0	0
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WYU	-46	0	0	0	-46	0	0	0	0
4501000 Total					**-6,917**	**-183**	**-3,121**	**-563**	**-453**	**-2,387**	**-210**	**0**	**0**

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	CA	-48	-48	0	0	0	0	0	0	0
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	IDU	-30	0	0	0	0	0	-30	0	0
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	OR	-809	0	-809	0	0	0	0	0	0
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	UT	-667	0	0	0	0	-667	0	0	0
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WA	-149	0	0	-149	0	0	0	0	0
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WYP	-110	0	0	0	-110	0	0	0	0
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WYU	-11	0	0	0	-11	0	0	0	0
4502000 Total					**-1,824**	**-48**	**-809**	**-149**	**-121**	**-667**	**-30**	**0**	**0**
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	CA	-26	-26	0	0	0	0	0	0	0
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	IDU	-98	0	0	0	0	0	-98	0	0
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	OR	-270	0	-270	0	0	0	0	0	0
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	UT	-206	0	0	0	0	-206	0	0	0
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WA	-28	0	0	-28	0	0	0	0	0
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WYP	-35	0	0	0	-35	0	0	0	0
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WYU	-9	0	0	0	-9	0	0	0	0
4503000 Total					**-672**	**-26**	**-270**	**-28**	**-45**	**-206**	**-98**	**0**	**0**
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	CA	-2	-2	0	0	0	0	0	0	0
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	IDU	-3	0	0	0	0	0	-3	0	0
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	OR	-42	0	-42	0	0	0	0	0	0
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	UT	-130	0	0	0	0	-130	0	0	0
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	WA	-4	0	0	-4	0	0	0	0	0
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	WYP	5	0	0	0	5	0	0	0	0
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	WYU	0	0	0	0	0	0	0	0	0
4504000 Total					**-176**	**-2**	**-42**	**-4**	**5**	**-130**	**-3**	**0**	**0**
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	CA	-201	-201	0	0	0	0	0	0	0
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	IDU	-47	0	0	0	0	0	-47	0	0
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	OR	-1,813	0	-1,813	0	0	0	0	0	0
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	UT	-2,638	0	0	0	0	-2,638	0	0	0
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WA	-60	0	0	-60	0	0	0	0	0
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WYP	-97	0	0	0	-97	0	0	0	0
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WYU	-8	0	0	0	-8	0	0	0	0
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	CA	-11	-11	0	0	0	0	0	0	0
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	IDU	-34	0	0	0	0	0	-34	0	0
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	OR	-301	0	-301	0	0	0	0	0	0
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	UT	-519	0	0	0	0	-519	0	0	0
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WA	-61	0	0	-61	0	0	0	0	0
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WYP	-82	0	0	0	-82	0	0	0	0
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WYU	-10	0	0	0	-10	0	0	0	0
4511000 Total					**-5,881**	**-212**	**-2,115**	**-121**	**-196**	**-3,157**	**-81**	**0**	**0**
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHGS	CA	-2	-2	0	0	0	0	0	0	0
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHGS	IDU	0	0	0	0	0	0	0	0	0
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHGS	OR	-9	0	-9	0	0	0	0	0	0
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHGS	SO	-4	0	-1	0	-1	-2	0	0	0
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHGS	UT	-4	0	0	0	0	-4	0	0	0

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(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHGS	WA	-2	0	0	-2	0	0	0	0	0
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHGS	WYP	0	0	0	0	0	0	0	0	0
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHGS	WYU	0	0	0	0	0	0	0	0	0
4512000 Total					**-21**	**-2**	**-10**	**-2**	**-1**	**-6**	**-1**	**0**	**0**
4513000	OTHER	301828	OTHER	CA	-70	-70	0	0	0	0	0	0	0
4513000	OTHER	301828	OTHER	IDU	-1	0	0	0	0	0	-1	0	0
4513000	OTHER	301828	OTHER	OR	-328	0	-328	0	0	0	0	0	0
4513000	OTHER	301828	OTHER	SO	-31	-1	-8	-2	-4	-13	-2	0	0
4513000	OTHER	301828	OTHER	UT	-473	0	0	0	0	-473	0	0	0
4513000	OTHER	301828	OTHER	WA	-8	0	0	-8	0	0	0	0	0
4513000	OTHER	301828	OTHER	WYP	-93	0	0	0	-93	0	0	0	0
4513000	OTHER	301828	OTHER	WYU	-5	0	0	0	-5	0	0	0	0
4513000	OTHER	301840	Miscellaneous Service Revenue	CA	-1	-1	0	0	0	0	0	0	0
4513000	OTHER	301840	Miscellaneous Service Revenue	OR	-10	0	-10	0	0	0	0	0	0
4513000	OTHER	301840	Miscellaneous Service Revenue	UT	-296	0	0	0	0	-296	0	0	0
4513000	OTHER	301840	Miscellaneous Service Revenue	WA	-30	0	0	-30	0	0	0	0	0
4513000 Total					**-1,347**	**-72**	**-347**	**-40**	**-102**	**-783**	**-3**	**0**	**0**
4514100	ENERGY FINANSWER	301836	ENERGY FINAN - NEW COMM	UT	-1	0	0	0	0	-1	0	0	0
4514100 Total					**-1**	**0**	**0**	**0**	**0**	**-1**	**0**	**0**	**0**
4530000	SLS WATER & W PWR	358900	Sales of Water & Water Power	SG	-58	-1	-15	-5	-9	-26	-3	0	0
4530000 Total					**-58**	**-1**	**-15**	**-5**	**-9**	**-26**	**-3**	**0**	**0**
4541000	RENTS - COMMON	0	4541000/0	SO	-2	0	-1	0	0	-1	0	0	0
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	CA	-2	-2	0	0	0	0	0	0	0
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	IDU	-1	0	0	0	0	0	-1	0	0
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	OR	-849	0	-849	0	0	0	0	0	0
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	SG	-95	-1	-25	-7	-14	-42	-6	0	0
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	SO	-830	-19	-226	-64	-113	-361	-48	0	0
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	UT	-590	0	0	0	0	-590	0	0	0
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	WA	-11	0	0	-11	0	0	0	0	0
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	WYP	-14	0	0	0	-14	0	0	0	0
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	WYU	-18	0	0	0	-18	0	0	0	0
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	CA	-507	-507	0	0	0	0	0	0	0
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	IDU	-164	0	0	0	0	0	-164	0	0
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	OR	-2,509	0	-2,509	0	0	0	0	0	0
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	UT	-1,903	0	0	0	0	-1,903	0	0	0
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	WA	-664	0	0	-664	0	0	0	0	0
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	WYP	-332	0	0	0	-332	0	0	0	0
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	CA	0	0	0	0	0	0	0	0	0
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	IDU	-5	0	0	0	0	0	-5	0	0
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	OR	-6	0	-6	0	0	0	0	0	0
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	SG	0	0	0	0	0	0	0	0	0
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	UT	0	0	0	0	0	0	0	0	0
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	WYP	0	0	0	0	0	0	0	0	0
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	CA	-12	-12	0	0	0	0	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	OR	-69	0	-69	0	0	0	0	0	0
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	UT	-677	0	0	0	0	-677	0	0	0
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	WA	-14	0	0	-14	0	0	0	0	0
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	WYP	-20	0	0	0	-20	0	0	0	0
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	CA	3	3	0	0	0	0	0	0	0
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	OR	-25	0	-25	0	0	0	0	0	0
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	UT	-34	0	0	0	0	-34	0	0	0
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	WA	-1	0	0	-1	0	0	0	0	0
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	WYP	3	0	0	0	3	0	0	0	0
4541000	RENTS - COMMON	301870	RENT REV - STEAM	SG	-208	-3	-54	-16	-30	-91	-12	0	0
4541000	RENTS - COMMON	301871	RENT REV - HYDRO	SG	-461	-7	-120	-36	-67	-203	-27	0	0
4541000	RENTS - COMMON	301872	RENT REV - TRANS	SG	-1,661	-26	-432	-131	-243	-731	-98	0	0
4541000	RENTS - COMMON	301873	RENT REV - DIST	SO	-132	-3	-36	-10	-18	-57	-8	0	0
4541000	RENTS - COMMON	301873	RENT REV - DIST	UT	-683	0	0	0	0	-683	0	0	0
4541000	RENTS - COMMON	301874	RENT REV - GENERAL	SG	-76	-1	-20	-6	-11	-33	-4	0	0
4541000	RENTS - COMMON	301874	RENT REV - GENERAL	SO	-106	-2	-29	-8	-14	-46	-6	0	0
4541000	RENTS - COMMON	301875	RENT REV - CORP	SO	-7	0	-2	-1	-1	-3	0	0	0
4541000	RENTS - COMMON	301878	JOINT USE BACK RENT	OR	0	0	0	0	0	0	0	0	0
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	CA	-44	-44	0	0	0	0	0	0	0
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	IDU	-4	0	0	0	0	0	-4	0	0
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	OR	-264	0	-264	0	0	0	0	0	0
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	UT	-34	0	0	0	0	-34	0	0	0
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	WA	-38	0	0	-38	0	0	0	0	0
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	WYP	-9	0	0	0	-9	0	0	0	0
4541000	RENTS - COMMON	301885	RENT REVENUE - SUBLE	SG	-33	-1	-9	-3	-5	-14	-2	0	0
4541000	RENTS - COMMON	301885	RENT REVENUE - SUBLE	SO	-622	-14	-169	-48	-85	-271	-36	0	0
4541000	RENTS - COMMON	301885	RENT REVENUE - SUBLE	UT	-12	0	0	0	0	-12	0	0	0
4541000 Total					**-13,746**	**-638**	**-4,846**	**-1,060**	**-992**	**-5,787**	**-422**	**-1**	**0**
4542000	RENTS - NON COMMON	301862	RENTS - NON COMMON	SG	-14	0	-4	-1	-2	-6	-1	0	0
4542000	RENTS - NON COMMON	301862	RENTS - NON COMMON	SO	-1	0	0	0	0	0	0	0	0
4542000	RENTS - NON COMMON	301862	RENTS - NON COMMON	UT	-1	0	0	0	0	-1	0	0	0
4542000 Total					**-16**	**0**	**-4**	**-1**	**-2**	**-8**	**-1**	**0**	**0**
4543000	MCI FOGWIRE REVENUES	301863	MCI FIBER OPTIC GROUND WIRE REVENUES	SG	-3,349	-51	-872	-264	-490	-1,474	-198	-1	0
4543000 Total					**-3,349**	**-51**	**-872**	**-264**	**-490**	**-1,474**	**-198**	**-1**	**0**
4545000	VERT BRIDGE REVENUES	367222	Joint Use - Vertical Bridge Applic Fee	SG	-3	0	-1	0	0	-1	0	0	0
4545000 Total					**-3**	**0**	**-1**	**0**	**0**	**-1**	**0**	**0**	**0**
4561100	Other Wheeling Rev	301952	Ancillary Rev Sch 6-Supp (Transm)	SG	532	8	138	42	78	234	31	0	0
4561100	Other Wheeling Rev	301953	Ancillary Rev Sch 6-Supp (C&T)	SG	-1,667	-26	-434	-132	-244	-733	-98	0	0
4561100	Other Wheeling Rev	301963	Ancil Revenue Sch 2-Reactive (C&T)	SG	-1,033	-16	-269	-82	-151	-454	-61	0	0
4561100	Other Wheeling Rev	301966	Primary Delivery and Distribution Sub Ch	SG	-496	-8	-129	-39	-73	-218	-29	0	0
4561100	Other Wheeling Rev	301967	Ancillary Revenue Sch 1 - Scheduling	SG	-2,041	-31	-531	-161	-299	-898	-120	-1	0
4561100	Other Wheeling Rev	301969	Ancillary Revenue Sch 3 - Reg&Freq (C&T)	SG	-3,131	-48	-815	-247	-458	-1,378	-185	-1	0
4561100	Other Wheeling Rev	301972	Ancillary Revenue Sch 5&6-Spin&Supp (Tra	SG	248	4	64	20	36	109	15	0	0
4561100	Other Wheeling Rev	301973	Ancillary Revenue Sch 5&6-Spin&Supp (C&T	SG	-1,705	-26	-444	-135	-249	-750	-101	0	0

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Electric Operations Revenue
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4561100	Other Wheeling Rev	301974	Ancil Revenue Sch 3a-Regulation (C&T)	SG	-3,805	-58	-990	-300	-556	-1,674	-224	-1	0
4561100	Other Wheeling Rev	302082	I/C Anc Rev Sch 1-Scheduling-Nevada Pwr	SG	-10	0	-3	-1	-1	-4	-1	0	0
4561100	Other Wheeling Rev	302092	I/C Anc Rev Sch 2-Reactive-Nevada Pwr	SG	-7	0	-2	-1	-1	-3	0	0	0
4561100	Other Wheeling Rev	302831	I/C Other Wheeling Revenue-Sierra Pac	SG	-36	-1	-9	-3	-5	-16	-2	0	0
4561100	Other Wheeling Rev	302832	I/C Other Wheeling Revenue-Nevada Pwr	SG	1	0	0	0	0	0	0	0	0
4561100	Other Wheeling Rev	302901	USE OF FACILITY REVENUE	SG	-895	-14	-233	-71	-131	-394	-53	0	0
4561100	Other Wheeling Rev	302981	Transmission Resales to Other Parties	SG	-557	-9	-145	-44	-82	-245	-33	0	0
4561100	Other Wheeling Rev	302982	Transmission Rev-Unreserved Use Charges	SG	-993	-15	-258	-78	-145	-437	-59	0	0
4561100	Other Wheeling Rev	302983	Transmission Revenue - Deferral Fees	SG	-120	-2	-31	-9	-17	-53	-7	0	0
4561100 Total					**-15,715**	**-241**	**-4,089**	**-1,240**	**-2,298**	**-6,914**	**-927**	**-4**	**0**
4561910	S/T FIRM WHEEL REV	301926	SHORT TERM FIRM WHEELING	SG	-3,338	-51	-869	-263	-488	-1,469	-197	-1	0
4561910	S/T FIRM WHEEL REV	302812	I/C ST Firm Wheeling Revenue-Nevada Pwr	SG	-386	-6	-100	-30	-56	-170	-23	0	0
4561910 Total					**-3,724**	**-57**	**-969**	**-294**	**-545**	**-1,638**	**-220**	**-1**	**0**
4561920	L/T FIRM WHEEL REV	301912	POST-MERGER FIRM WHEELING	SG	-13,663	-210	-3,555	-1,078	-1,998	-6,011	-806	-4	0
4561920	L/T FIRM WHEEL REV	301916	PRE-MERGER FIRM WHEELING	SG	-7,750	-119	-2,017	-612	-1,133	-3,410	-457	-2	0
4561920	L/T FIRM WHEEL REV	301917	PRE-MERGER FIRM WHEELING	SG	-23,579	-362	-6,136	-1,861	-3,448	-10,374	-1,391	-7	0
4561920	L/T FIRM WHEEL REV	302980	Transmisson Point-to-Point Revenue	SG	-32,394	-498	-8,430	-2,557	-4,738	-14,253	-1,910	-9	0
4561920 Total					**-77,386**	**-1,189**	**-20,138**	**-6,107**	**-11,318**	**-34,048**	**-4,564**	**-22**	**0**
4561930	NON-FIRM WHEEL REV	301922	NON-FIRM WHEELING REVENUE	SE	-17,029	-248	-4,274	-1,280	-2,721	-7,383	-1,117	-6	0
4561930	NON-FIRM WHEEL REV	302822	I/C Non-Firm Wheeling Revenue-Nevada Pwr	SE	0	0	0	0	0	0	0	0	0
4561930 Total					**-17,029**	**-248**	**-4,274**	**-1,280**	**-2,721**	**-7,383**	**-1,117**	**-6**	**0**
4561990	TRANSMN REV REFUND	301913	Transmission Tariff True-up	SG	-679	-10	-177	-54	-99	-299	-40	0	0
4561990	TRANSMN REV REFUND	305950	Ancil Revenue Sch 5 - Subject to Refund	SG	-248	-4	-64	-20	-36	-109	-15	0	0
4561990	TRANSMN REV REFUND	305960	Ancil Revenue Sch 6 - Subject to Refund	SG	-532	-8	-138	-42	-78	-234	-31	0	0
4561990 Total					**-1,459**	**-22**	**-380**	**-115**	**-213**	**-642**	**-86**	**0**	**0**
4562100	USE OF FACIL REV	301911	"INCOME FROM FISH, WILDLIFE"	SG	-22	0	-6	-2	-3	-10	-1	0	0
4562100 Total					**-22**	**0**	**-6**	**-2**	**-3**	**-10**	**-1**	**0**	**0**
4562300	MISC OTHER REV	301900	ELECTRIC INCOME OTHER	SG	-36	-1	-9	-3	-5	-16	-2	0	0
4562300	MISC OTHER REV	301900	ELECTRIC INCOME OTHER	UT	-24	0	0	0	0	-24	0	0	0
4562300	MISC OTHER REV	301901	WASHINGTON - COLSTRIP 3	WA	52	0	0	52	0	0	0	0	0
4562300	MISC OTHER REV	301915	OTHER ELEC REV - MISC	SG	-1,670	-26	-435	-132	-244	-735	-98	0	0
4562300	MISC OTHER REV	301939	Estimated Other Electric Revenue	SG	-16	0	-4	-1	-2	-7	-1	0	0
4562300	MISC OTHER REV	301940	FLYASH & BY-PRODUCT SALES	SG	-4,256	-65	-1,108	-336	-622	-1,873	-251	-1	0
4562300	MISC OTHER REV	301949	THIRD PARTY TRN O&M REV	SG	-368	-6	-96	-29	-54	-162	-22	0	0
4562300	MISC OTHER REV	301951	NON-WHEELING SYS REV	SG	-538	-8	-140	-42	-79	-237	-32	0	0
4562300	MISC OTHER REV	301955	OTHER REV WY REG KENNECOTT	WYP	-186	0	0	0	-186	0	0	0	0
4562300	MISC OTHER REV	301958	Wind-based Ancillary Services Estimate	SG	-93	-1	-24	-7	-14	-41	-6	0	0
4562300	MISC OTHER REV	301959	Wind-based Ancillary Services/Revenue	SG	-9,931	-153	-2,584	-784	-1,452	-4,369	-586	-3	0
4562300	MISC OTHER REV	302071	I/C Transmission O&M Revenue-Sierra Pac	SG	-8	0	-2	-1	-1	-4	0	0	0
4562300	MISC OTHER REV	361000	STEAM SALES	SG	-633	-10	-165	-50	-93	-278	-37	0	0
4562300	MISC OTHER REV	362100	Refined Coal Transaction Fee Revenue	SG	35	1	9	3	5	15	2	0	0
4562300	MISC OTHER REV	374400	Timber Sales - Utility Property	SG	-506	-8	-132	-40	-74	-223	-30	0	0
4562300 Total					**-18,178**	**-277**	**-4,689**	**-1,370**	**-2,822**	**-7,952**	**-1,063**	**-5**	**0**
4562310	EIM - MISCELLANEOUS	308001	EIM Rev-Forecasting Fee: Pac to TC	SG	-15	0	-4	-1	-2	-6	-1	0	0

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Electric Operations Revenue
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4562310 Total					**-15**	**0**	**-4**	**-1**	**-2**	**-6**	**-1**	**0**	**0**
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	OR	0	0	0	0	0	0	0	0	0
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	SG	-2	0	-1	0	0	-1	0	0	0
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	SO	-4,092	-91	-1,114	-315	-556	-1,780	-235	-1	0
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	UT	-47	0	0	0	0	-47	0	0	0
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	WYP	0	0	0	0	0	0	0	0	0
4562400 Total					**-4,142**	**-91**	**-1,114**	**-315**	**-557**	**-1,828**	**-235**	**-1**	**0**
4562500	M&S INV COST OF SALE	514950	M&S INVENTORY COST OF SALES	UT	4,536	0	0	0	0	4,536	0	0	0
4562500 Total					**4,536**	**0**	**0**	**0**	**0**	**4,536**	**0**	**0**	**0**
4562700	RNW ENRGY CRDT SALES	301943	Renewable Energy Credit Sales-Deferral	SG	130	2	34	10	19	57	8	0	0
4562700	RNW ENRGY CRDT SALES	301944	Renewable Energy Credit Sales-Estimate	SG	-323	-5	-84	-26	-47	-142	-19	0	0
4562700	RNW ENRGY CRDT SALES	301945	Renewable Energy Credit Sales	SG	-3,438	-53	-895	-271	-503	-1,513	-203	-1	0
4562700	RNW ENRGY CRDT SALES	352943	Renwbl En Cr Sls-Amt	OTHER	913	0	0	0	0	0	0	0	913
4562700	RNW ENRGY CRDT SALES	352950	REC Sales - Wind Wake Loss Indemnity	SG	-6	0	-2	0	-1	-3	0	0	0
4562700 Total					**-2,724**	**-56**	**-946**	**-287**	**-532**	**-1,600**	**-214**	**-1**	**913**
4562800	CA GHG Emission Allo	352001	CA GHG Allowance Revenues	OTHER	-12,011	0	0	0	0	0	0	0	-12,011
4562800	CA GHG Emission Allo	352002	CA GHG Allowance Revenues - Deferral	OTHER	11,663	0	0	0	0	0	0	0	11,663
4562800	CA GHG Emission Allo	352003	CA GHG Allowance Revenues – Amortz	OTHER	-10,816	0	0	0	0	0	0	0	-10,816
4562800	CA GHG Emission Allo	352004	CA GHG Allow Revenues - SOMAH Amortz	OTHER	-44	0	0	0	0	0	0	0	-44
4562800 Total					**-11,207**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-11,207**
4563500	Oth Elec Rev-Def Trn	305990	FERC Transmission Refund-Deferral	OR	10,945	0	10,945	0	0	0	0	0	0
4563500	Oth Elec Rev-Def Trn	305991	FERC Transmission Refund-Amortz	OR	-6,933	0	-6,933	0	0	0	0	0	0
4563500 Total					**4,012**	**0**	**4,012**	**0**	**0**	**0**	**0**	**0**	**0**
Grand Total Electric Operations Revenue					**-5,159,799**	**-106,450**	**-1,367,388**	**-357,936**	**-730,941**	**-2,182,512**	**-306,754**	**-14,271**	**-93,547**
4118000	GAINS-DISP OF ALLOW	0	SO2 ALLOWANCE	SE	0	0	0	0	0	0	0	0	0
4118000 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	OR	715	0	715	0	0	0	0	0	0
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	SG	-137	-2	-36	-11	-20	-60	-8	0	0
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	SO	-3,965	-88	-1,079	-305	-539	-1,725	-228	-1	0
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	UT	-16	0	0	0	0	-16	0	0	0
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	WA	-1	0	0	-1	0	0	0	0	0
4211000 Total					**-3,404**	**-91**	**-400**	**-317**	**-559**	**-1,801**	**-236**	**-1**	**0**
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	CA	15	15	0	0	0	0	0	0	0
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	OR	17	0	17	0	0	0	0	0	0
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	SG	27	0	7	2	4	12	2	0	0
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	SO	14	0	4	1	2	6	1	0	0
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	WYP	0	0	0	0	0	0	0	0	0
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	WYU	5	0	0	0	5	0	0	0	0
4212000 Total					**78**	**16**	**28**	**3**	**11**	**18**	**2**	**0**	**0**
Grand Total Miscellaneous Revenue					**-3,327**	**-75**	**-373**	**-314**	**-548**	**-1,783**	**-233**	**-1**	**0**

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Operations & Maintenance Expense

Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5000000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	17,996	277	4,683	1,420	2,632	7,918	1,061	5	0
5000000 Total					**17,996**	**277**	**4,683**	**1,420**	**2,632**	**7,918**	**1,061**	**5**	**0**
5001000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	64	1	17	5	9	28	4	0	0
5001000 Total					**64**	**1**	**17**	**5**	**9**	**28**	**4**	**0**	**0**
5010000	FUEL CONSUMED	NPCX	Net Power Cost Expense	SE	3,620	53	909	272	578	1,570	237	1	0
5010000 Total					**3,620**	**53**	**909**	**272**	**578**	**1,570**	**237**	**1**	**0**
5011000	FUEL CONSUMED-COAL	NPCX	Net Power Cost Expense	SE	754,530	10,974	189,398	56,724	120,574	327,136	49,479	246	0
5011000 Total					**754,530**	**10,974**	**189,398**	**56,724**	**120,574**	**327,136**	**49,479**	**246**	**0**
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	IDU	104	0	0	0	0	0	104	0	0
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	WYP	294	0	0	0	294	0	0	0	0
5011200 Total					**398**	**0**	**0**	**0**	**294**	**0**	**104**	**0**	**0**
5011500	FUEL REG CST DFRL AM	STEX	Steam O&M Expense	CA	-167	-167	0	0	0	0	0	0	0
5011500	FUEL REG CST DFRL AM	STEX	Steam O&M Expense	OR	1,882	0	1,882	0	0	0	0	0	0
5011500	FUEL REG CST DFRL AM	STEX	Steam O&M Expense	SE	7,095	103	1,781	533	1,134	3,076	465	2	0
5011500	FUEL REG CST DFRL AM	STEX	Steam O&M Expense	WA	-748	0	0	-748	0	0	0	0	0
5011500	FUEL REG CST DFRL AM	STEX	Steam O&M Expense	WYP	779	0	0	0	779	0	0	0	0
5011500 Total					**8,842**	**-64**	**3,663**	**-214**	**1,913**	**3,076**	**465**	**2**	**0**
5012000	FUEL HAND-COAL	STEX	Steam O&M Expense	SE	9,201	134	2,310	692	1,470	3,989	603	3	0
5012000 Total					**9,201**	**134**	**2,310**	**692**	**1,470**	**3,989**	**603**	**3**	**0**
5013000	START UP FUEL - GAS	NPCX	Net Power Cost Expense	SE	291	4	73	22	46	126	19	0	0
5013000 Total					**291**	**4**	**73**	**22**	**46**	**126**	**19**	**0**	**0**
5013500	FUEL CONSUMED-GAS	NPCX	Net Power Cost Expense	SE	4,583	67	1,150	345	732	1,987	301	1	0
5013500 Total					**4,583**	**67**	**1,150**	**345**	**732**	**1,987**	**301**	**1**	**0**
5014000	FUEL CONSUMED-DIESEL	NPCX	Net Power Cost Expense	SE	26	0	7	2	4	11	2	0	0
5014000 Total					**26**	**0**	**7**	**2**	**4**	**11**	**2**	**0**	**0**
5014500	START UP FUEL-DIESEL	NPCX	Net Power Cost Expense	SE	5,519	80	1,385	415	882	2,393	362	2	0
5014500 Total					**5,519**	**80**	**1,385**	**415**	**882**	**2,393**	**362**	**2**	**0**
5015000	FUEL CONS-RES DISP	NPCX	Net Power Cost Expense	SE	123	2	31	9	20	53	8	0	0
5015000 Total					**123**	**2**	**31**	**9**	**20**	**53**	**8**	**0**	**0**
5015100	ASH & ASH BYPRD SALE	NPCX	Net Power Cost Expense	SE	0	0	0	0	0	0	0	0	0
5015100 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
5020000	STEAM EXPENSES	STEX	Steam O&M Expense	SG	47,916	736	12,469	3,782	7,008	21,082	2,826	14	0
5020000 Total					**47,916**	**736**	**12,469**	**3,782**	**7,008**	**21,082**	**2,826**	**14**	**0**
5022000	STM EXP - FLYASH	STEX	Steam O&M Expense	SG	3,087	47	803	244	451	1,358	182	1	0
5022000 Total					**3,087**	**47**	**803**	**244**	**451**	**1,358**	**182**	**1**	**0**
5023000	STM EXP BOTTOM ASH	STEX	Steam O&M Expense	SG	250	4	65	20	37	110	15	0	0
5023000 Total					**250**	**4**	**65**	**20**	**37**	**110**	**15**	**0**	**0**

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5024000	STM EXP SCRUBBER	STEX	Steam O&M Expense	SG	7,917	122	2,060	625	1,158	3,483	467	2	0
5024000 Total					**7,917**	**122**	**2,060**	**625**	**1,158**	**3,483**	**467**	**2**	**0**
5029000	STM EXP - OTHER	STEX	Steam O&M Expense	SG	23,078	355	6,005	1,821	3,375	10,154	1,361	7	0
5029000 Total					**23,078**	**355**	**6,005**	**1,821**	**3,375**	**10,154**	**1,361**	**7**	**0**
5030000	STEAM FRM OTH SRCS	NPCX	Net Power Cost Expense	SE	4,571	66	1,147	344	730	1,982	300	1	0
5030000 Total					**4,571**	**66**	**1,147**	**344**	**730**	**1,982**	**300**	**1**	**0**
5050000	ELECTRIC EXPENSES	STEX	Steam O&M Expense	SG	1,564	24	407	123	229	688	92	0	0
5050000 Total					**1,564**	**24**	**407**	**123**	**229**	**688**	**92**	**0**	**0**
5051000	ELEC EXP GENERAL	STEX	Steam O&M Expense	SG	3	0	1	0	0	1	0	0	0
5051000 Total					**3**	**0**	**1**	**0**	**0**	**1**	**0**	**0**	**0**
5060000	MISC STEAM PWR EXP	STEX	Steam O&M Expense	SG	51,614	793	13,431	4,073	7,549	22,709	3,044	15	0
5060000 Total					**51,614**	**793**	**13,431**	**4,073**	**7,549**	**22,709**	**3,044**	**15**	**0**
5061000	MISC STM EXP - CON	STEX	Steam O&M Expense	SG	738	11	192	58	108	325	44	0	0
5061000 Total					**738**	**11**	**192**	**58**	**108**	**325**	**44**	**0**	**0**
5061100	MISC STM EXP PLCLU	STEX	Steam O&M Expense	SG	1,147	18	299	91	168	505	68	0	0
5061100 Total					**1,147**	**18**	**299**	**91**	**168**	**505**	**68**	**0**	**0**
5061200	MISC STM EXP UNMTG	STEX	Steam O&M Expense	SG	3	0	1	0	0	1	0	0	0
5061200 Total					**3**	**0**	**1**	**0**	**0**	**1**	**0**	**0**	**0**
5061300	MISC STM EXP COMPT	STEX	Steam O&M Expense	SG	394	6	102	31	58	173	23	0	0
5061300 Total					**394**	**6**	**102**	**31**	**58**	**173**	**23**	**0**	**0**
5061400	MISC STM EXP OFFIC	STEX	Steam O&M Expense	SG	2,272	35	591	179	332	1,000	134	1	0
5061400 Total					**2,272**	**35**	**591**	**179**	**332**	**1,000**	**134**	**1**	**0**
5061500	MISC STM EXP COMM	STEX	Steam O&M Expense	SG	217	3	56	17	32	95	13	0	0
5061500 Total					**217**	**3**	**56**	**17**	**32**	**95**	**13**	**0**	**0**
5061600	MISC STM EXP FIRE	STEX	Steam O&M Expense	SG	45	1	12	4	7	20	3	0	0
5061600 Total					**45**	**1**	**12**	**4**	**7**	**20**	**3**	**0**	**0**
5062000	MISC STM - ENVRMNT	STEX	Steam O&M Expense	SG	3,853	59	1,003	304	564	1,695	227	1	0
5062000 Total					**3,853**	**59**	**1,003**	**304**	**564**	**1,695**	**227**	**1**	**0**
5063000	MISC STEAM JVA CR	STEX	Steam O&M Expense	SG	-41,757	-642	-10,866	-3,295	-6,107	-18,372	-2,463	-12	0
5063000 Total					**-41,757**	**-642**	**-10,866**	**-3,295**	**-6,107**	**-18,372**	**-2,463**	**-12**	**0**
5064000	MISC STM EXP RCRT	STEX	Steam O&M Expense	SG	49	1	13	4	7	21	3	0	0
5064000 Total					**49**	**1**	**13**	**4**	**7**	**21**	**3**	**0**	**0**
5065000	MISC STM EXP - SEC	STEX	Steam O&M Expense	SG	570	9	148	45	83	251	34	0	0
5065000 Total					**570**	**9**	**148**	**45**	**83**	**251**	**34**	**0**	**0**
5066000	MISC STM EXP -SFTY	STEX	Steam O&M Expense	SG	1,249	19	325	99	183	550	74	0	0
5066000 Total					**1,249**	**19**	**325**	**99**	**183**	**550**	**74**	**0**	**0**
5067000	MISC STM EXP TRNNG	STEX	Steam O&M Expense	SG	4,598	71	1,196	363	672	2,023	271	1	0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5067000 Total					**4,598**	**71**	**1,196**	**363**	**672**	**2,023**	**271**	**1**	**0**
5069000	MISC STM EXP WTSPY	STEX	Steam O&M Expense	SG	790	12	205	62	115	347	47	0	0
5069000 Total					**790**	**12**	**205**	**62**	**115**	**347**	**47**	**0**	**0**
5069900	MISC STM EXP MISC	STEX	Steam O&M Expense	SG	3,467	53	902	274	507	1,525	204	1	0
5069900 Total					**3,467**	**53**	**902**	**274**	**507**	**1,525**	**204**	**1**	**0**
5070000	RENTS (STEAM GEN)	STEX	Steam O&M Expense	SG	516	8	134	41	75	227	30	0	0
5070000 Total					**516**	**8**	**134**	**41**	**75**	**227**	**30**	**0**	**0**
5100000	MNT SUPERV & ENG	STEX	Steam O&M Expense	SG	4,854	75	1,263	383	710	2,136	286	1	0
5100000 Total					**4,854**	**75**	**1,263**	**383**	**710**	**2,136**	**286**	**1**	**0**
5101000	MNTNCE SUPVSN &ENG	STEX	Steam O&M Expense	SG	3,236	50	842	255	473	1,424	191	1	0
5101000 Total					**3,236**	**50**	**842**	**255**	**473**	**1,424**	**191**	**1**	**0**
5110000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	6,168	95	1,605	487	902	2,714	364	2	0
5110000 Total					**6,168**	**95**	**1,605**	**487**	**902**	**2,714**	**364**	**2**	**0**
5111000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	3,898	60	1,014	308	570	1,715	230	1	0
5111000 Total					**3,898**	**60**	**1,014**	**308**	**570**	**1,715**	**230**	**1**	**0**
5111100	MNT STRCT PMP PLNT	STEX	Steam O&M Expense	SG	721	11	188	57	105	317	43	0	0
5111100 Total					**721**	**11**	**188**	**57**	**105**	**317**	**43**	**0**	**0**
5111200	MNT STRCT WASTE WT	STEX	Steam O&M Expense	SG	925	14	241	73	135	407	55	0	0
5111200 Total					**925**	**14**	**241**	**73**	**135**	**407**	**55**	**0**	**0**
5112000	STRUCTURAL SYSTEMS	STEX	Steam O&M Expense	SG	10,685	164	2,781	843	1,563	4,701	630	3	0
5112000 Total					**10,685**	**164**	**2,781**	**843**	**1,563**	**4,701**	**630**	**3**	**0**
5114000	MNT OF STRCT CATH	STEX	Steam O&M Expense	SG	26	0	7	2	4	11	2	0	0
5114000 Total					**26**	**0**	**7**	**2**	**4**	**11**	**2**	**0**	**0**
5116000	MNT STRCT DAM RIVR	STEX	Steam O&M Expense	SG	85	1	22	7	12	37	5	0	0
5116000 Total					**85**	**1**	**22**	**7**	**12**	**37**	**5**	**0**	**0**
5117000	MNT STRCT FIRE PRT	STEX	Steam O&M Expense	SG	1,359	21	354	107	199	598	80	0	0
5117000 Total					**1,359**	**21**	**354**	**107**	**199**	**598**	**80**	**0**	**0**
5118000	MNT STRCT-GROUNDS	STEX	Steam O&M Expense	SG	917	14	239	72	134	403	54	0	0
5118000 Total					**917**	**14**	**239**	**72**	**134**	**403**	**54**	**0**	**0**
5119000	MNT OF STRCT-HVAC	STEX	Steam O&M Expense	SG	1,602	25	417	126	234	705	94	0	0
5119000 Total					**1,602**	**25**	**417**	**126**	**234**	**705**	**94**	**0**	**0**
5119900	MNT OF STRCT-MISC	STEX	Steam O&M Expense	SG	405	6	105	32	59	178	24	0	0
5119900 Total					**405**	**6**	**105**	**32**	**59**	**178**	**24**	**0**	**0**
5120000	MANT OF BOILR PLNT	STEX	Steam O&M Expense	SG	14,345	220	3,733	1,132	2,098	6,312	846	4	0
5120000 Total					**14,345**	**220**	**3,733**	**1,132**	**2,098**	**6,312**	**846**	**4**	**0**
5121000	MNT BOILR-AIR HTR	STEX	Steam O&M Expense	SG	8,738	134	2,274	690	1,278	3,844	515	2	0
5121000 Total					**8,738**	**134**	**2,274**	**690**	**1,278**	**3,844**	**515**	**2**	**0**

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5121100	MNT BOILR-CHEM FD	STEX	Steam O&M Expense	SG	127	2	33	10	19	56	7	0	0
5121100 Total					**127**	**2**	**33**	**10**	**19**	**56**	**7**	**0**	**0**
5121200	MNT BOILR-CL HANDL	STEX	Steam O&M Expense	SG	5,054	78	1,315	399	739	2,224	298	1	0
5121200 Total					**5,054**	**78**	**1,315**	**399**	**739**	**2,224**	**298**	**1**	**0**
5121400	MNT BOIL-DEMINERLZ	STEX	Steam O&M Expense	SG	303	5	79	24	44	133	18	0	0
5121400 Total					**303**	**5**	**79**	**24**	**44**	**133**	**18**	**0**	**0**
5121500	MNT BOIL-EXTRC STM	STEX	Steam O&M Expense	SG	466	7	121	37	68	205	27	0	0
5121500 Total					**466**	**7**	**121**	**37**	**68**	**205**	**27**	**0**	**0**
5121600	MNT BOILR-FLYASH	STEX	Steam O&M Expense	SG	3,942	61	1,026	311	576	1,734	232	1	0
5121600 Total					**3,942**	**61**	**1,026**	**311**	**576**	**1,734**	**232**	**1**	**0**
5121700	MNT BOIL-FUEL OIL	STEX	Steam O&M Expense	SG	846	13	220	67	124	372	50	0	0
5121700 Total					**846**	**13**	**220**	**67**	**124**	**372**	**50**	**0**	**0**
5121800	MNT BOIL-FEEDWATR	STEX	Steam O&M Expense	SG	5,032	77	1,309	397	736	2,214	297	1	0
5121800 Total					**5,032**	**77**	**1,309**	**397**	**736**	**2,214**	**297**	**1**	**0**
5121900	MNT BOIL-FRZ PRTEC	STEX	Steam O&M Expense	SG	29	0	8	2	4	13	2	0	0
5121900 Total					**29**	**0**	**8**	**2**	**4**	**13**	**2**	**0**	**0**
5122000	MNT BOILR-AUX SYST	STEX	Steam O&M Expense	SG	610	9	159	48	89	268	36	0	0
5122000 Total					**610**	**9**	**159**	**48**	**89**	**268**	**36**	**0**	**0**
5122100	MNT BOILR-MAIN STM	STEX	Steam O&M Expense	SG	3,979	61	1,035	314	582	1,751	235	1	0
5122100 Total					**3,979**	**61**	**1,035**	**314**	**582**	**1,751**	**235**	**1**	**0**
5122200	MNT BOIL-PLVRZD CL	STEX	Steam O&M Expense	SG	8,361	128	2,176	660	1,223	3,679	493	2	0
5122200 Total					**8,361**	**128**	**2,176**	**660**	**1,223**	**3,679**	**493**	**2**	**0**
5122300	MNT BOIL-PRECIP/BAG	STEX	Steam O&M Expense	SG	3,982	61	1,036	314	582	1,752	235	1	0
5122300 Total					**3,982**	**61**	**1,036**	**314**	**582**	**1,752**	**235**	**1**	**0**
5122400	MNT BOIL-PRTRT WTR	STEX	Steam O&M Expense	SG	578	9	151	46	85	254	34	0	0
5122400 Total					**578**	**9**	**151**	**46**	**85**	**254**	**34**	**0**	**0**
5122500	MNT BOIL-RV OSMSIS	STEX	Steam O&M Expense	SG	141	2	37	11	21	62	8	0	0
5122500 Total					**141**	**2**	**37**	**11**	**21**	**62**	**8**	**0**	**0**
5122600	MNT BOIL-RHEAT ST	STEX	Steam O&M Expense	SG	976	15	254	77	143	430	58	0	0
5122600 Total					**976**	**15**	**254**	**77**	**143**	**430**	**58**	**0**	**0**
5122800	MNT BOIL-SOOTBLWG	STEX	Steam O&M Expense	SG	1,980	30	515	156	290	871	117	1	0
5122800 Total					**1,980**	**30**	**515**	**156**	**290**	**871**	**117**	**1**	**0**
5122900	MNT BOILR-SCRUBBER	STEX	Steam O&M Expense	SG	7,480	115	1,946	590	1,094	3,291	441	2	0
5122900 Total					**7,480**	**115**	**1,946**	**590**	**1,094**	**3,291**	**441**	**2**	**0**
5123000	MNT BOILR-BOTM ASH	STEX	Steam O&M Expense	SG	2,819	43	734	222	412	1,240	166	1	0
5123000 Total					**2,819**	**43**	**734**	**222**	**412**	**1,240**	**166**	**1**	**0**
5123100	MNT BOIL-WTR TRTMT	STEX	Steam O&M Expense	SG	321	5	84	25	47	141	19	0	0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5123100 Total					**321**	**5**	**84**	**25**	**47**	**141**	**19**	**0**	**0**
5123200	MNT BOIL-CNTL SUPT	STEX	Steam O&M Expense	SG	633	10	165	50	93	278	37	0	0
5123200 Total					**633**	**10**	**165**	**50**	**93**	**278**	**37**	**0**	**0**
5123300	MAINT GEO GATH SYS	STEX	Steam O&M Expense	SG	137	2	36	11	20	60	8	0	0
5123300 Total					**137**	**2**	**36**	**11**	**20**	**60**	**8**	**0**	**0**
5123400	MAINT OF BOILERS	STEX	Steam O&M Expense	SG	3,143	48	818	248	460	1,383	185	1	0
5123400 Total					**3,143**	**48**	**818**	**248**	**460**	**1,383**	**185**	**1**	**0**
5124000	MNT BOILR-CONTROLS	STEX	Steam O&M Expense	SG	1,266	19	329	100	185	557	75	0	0
5124000 Total					**1,266**	**19**	**329**	**100**	**185**	**557**	**75**	**0**	**0**
5125000	MNT BOILER-DRAFT	STEX	Steam O&M Expense	SG	3,623	56	943	286	530	1,594	214	1	0
5125000 Total					**3,623**	**56**	**943**	**286**	**530**	**1,594**	**214**	**1**	**0**
5126000	MNT BOILR-FIRESIDE	STEX	Steam O&M Expense	SG	2,988	46	778	236	437	1,315	176	1	0
5126000 Total					**2,988**	**46**	**778**	**236**	**437**	**1,315**	**176**	**1**	**0**
5127000	MNT BLR-BEARNG WTR	STEX	Steam O&M Expense	SG	269	4	70	21	39	118	16	0	0
5127000 Total					**269**	**4**	**70**	**21**	**39**	**118**	**16**	**0**	**0**
5128000	MNT BOILR WTR/STMD	STEX	Steam O&M Expense	SG	9,199	141	2,394	726	1,345	4,047	543	3	0
5128000 Total					**9,199**	**141**	**2,394**	**726**	**1,345**	**4,047**	**543**	**3**	**0**
5129000	MNT BOIL-COMP AIR	STEX	Steam O&M Expense	SG	406	6	106	32	59	179	24	0	0
5129000 Total					**406**	**6**	**106**	**32**	**59**	**179**	**24**	**0**	**0**
5129900	MAINT BOILER-MISC	STEX	Steam O&M Expense	SG	3,727	57	970	294	545	1,640	220	1	0
5129900 Total					**3,727**	**57**	**970**	**294**	**545**	**1,640**	**220**	**1**	**0**
5130000	MAINT ELEC PLANT	STEX	Steam O&M Expense	SG	2,247	35	585	177	329	989	133	1	0
5130000 Total					**2,247**	**35**	**585**	**177**	**329**	**989**	**133**	**1**	**0**
5131000	MAINT ELEC AC	STEX	Steam O&M Expense	SG	17,080	262	4,445	1,348	2,498	7,515	1,007	5	0
5131000 Total					**17,080**	**262**	**4,445**	**1,348**	**2,498**	**7,515**	**1,007**	**5**	**0**
5131100	MAINT/LUBE-OIL SYS	STEX	Steam O&M Expense	SG	663	10	172	52	97	292	39	0	0
5131100 Total					**663**	**10**	**172**	**52**	**97**	**292**	**39**	**0**	**0**
5131300	MAINT/PREVENT ROUT	STEX	Steam O&M Expense	SG	1	0	0	0	0	0	0	0	0
5131300 Total					**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
5131400	MAINT/MAIN TURBINE	STEX	Steam O&M Expense	SG	9,250	142	2,407	730	1,353	4,070	546	3	0
5131400 Total					**9,250**	**142**	**2,407**	**730**	**1,353**	**4,070**	**546**	**3**	**0**
5132000	MAINT ALARMS/INFO	STEX	Steam O&M Expense	SG	1,716	26	446	135	251	755	101	0	0
5132000 Total					**1,716**	**26**	**446**	**135**	**251**	**755**	**101**	**0**	**0**
5133000	MAINT/AIR-COOL-CON	STEX	Steam O&M Expense	SG	-12	0	-3	-1	-2	-5	-1	0	0
5133000 Total					**-12**	**0**	**-3**	**-1**	**-2**	**-5**	**-1**	**0**	**0**
5134000	MAINT/COMPNT COOL	STEX	Steam O&M Expense	SG	270	4	70	21	40	119	16	0	0
5134000 Total					**270**	**4**	**70**	**21**	**40**	**119**	**16**	**0**	**0**

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5135000	MAINT/COMPNT AUXIL	STEX	Steam O&M Expense	SG	1,321	20	344	104	193	581	78	0	0
5135000 Total					**1,321**	**20**	**344**	**104**	**193**	**581**	**78**	**0**	**0**
5137000	MAINT-COOLING TOWR	STEX	Steam O&M Expense	SG	1,363	21	355	108	199	600	80	0	0
5137000 Total					**1,363**	**21**	**355**	**108**	**199**	**600**	**80**	**0**	**0**
5138000	MAINT-CIRCUL WATER	STEX	Steam O&M Expense	SG	1,623	25	422	128	237	714	96	0	0
5138000 Total					**1,623**	**25**	**422**	**128**	**237**	**714**	**96**	**0**	**0**
5139000	MAINT-ELECT - DC	STEX	Steam O&M Expense	SG	319	5	83	25	47	140	19	0	0
5139000 Total					**319**	**5**	**83**	**25**	**47**	**140**	**19**	**0**	**0**
5139900	MNT ELEC PLT-MISC	STEX	Steam O&M Expense	SG	39	1	10	3	6	17	2	0	0
5139900 Total					**39**	**1**	**10**	**3**	**6**	**17**	**2**	**0**	**0**
5140000	MAINT MISC STM PLN	STEX	Steam O&M Expense	SG	3,682	57	958	291	539	1,620	217	1	0
5140000 Total					**3,682**	**57**	**958**	**291**	**539**	**1,620**	**217**	**1**	**0**
5141000	MISC STM-COMP AIR	STEX	Steam O&M Expense	SG	1,416	22	368	112	207	623	83	0	0
5141000 Total					**1,416**	**22**	**368**	**112**	**207**	**623**	**83**	**0**	**0**
5142000	MISC STM PLT-CONSU	STEX	Steam O&M Expense	SG	125	2	33	10	18	55	7	0	0
5142000 Total					**125**	**2**	**33**	**10**	**18**	**55**	**7**	**0**	**0**
5144000	MISC STM PLNT-LAB	STEX	Steam O&M Expense	SG	383	6	100	30	56	168	23	0	0
5144000 Total					**383**	**6**	**100**	**30**	**56**	**168**	**23**	**0**	**0**
5145000	MAINT MISC-SM TOOL	STEX	Steam O&M Expense	SG	508	8	132	40	74	223	30	0	0
5145000 Total					**508**	**8**	**132**	**40**	**74**	**223**	**30**	**0**	**0**
5146000	MAINT/PAGING SYS	STEX	Steam O&M Expense	SG	200	3	52	16	29	88	12	0	0
5146000 Total					**200**	**3**	**52**	**16**	**29**	**88**	**12**	**0**	**0**
5147000	MAINT/PLANT EQUIP	STEX	Steam O&M Expense	SG	1,334	20	347	105	195	587	79	0	0
5147000 Total					**1,334**	**20**	**347**	**105**	**195**	**587**	**79**	**0**	**0**
5148000	MAINT/PLT-VEHICLES	STEX	Steam O&M Expense	SG	1,798	28	468	142	263	791	106	1	0
5148000 Total					**1,798**	**28**	**468**	**142**	**263**	**791**	**106**	**1**	**0**
5149000	MAINT MISC-OTHER	STEX	Steam O&M Expense	SG	-47	-1	-12	-4	-7	-20	-3	0	0
5149000 Total					**-47**	**-1**	**-12**	**-4**	**-7**	**-20**	**-3**	**0**	**0**
5149500	MAINT STM PLT-ENV AM	STEX	Steam O&M Expense	SO	0	0	0	0	0	0	0	0	0
5149500	MAINT STM PLT-ENV AM	STEX	Steam O&M Expense	SG	966	15	251	76	141	425	57	0	0
5149500 Total					**966**	**15**	**251**	**76**	**141**	**425**	**57**	**0**	**0**
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	7,989	123	2,079	631	1,168	3,515	471	2	0
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-U	823	13	214	65	120	362	49	0	0
5350000 Total					**8,812**	**135**	**2,293**	**695**	**1,289**	**3,877**	**520**	**2**	**0**
5360000	WATER FOR POWER	HYEX	Hydro O&M Expense	SG-P	39	1	10	3	6	17	2	0	0
5360000 Total					**39**	**1**	**10**	**3**	**6**	**17**	**2**	**0**	**0**
5370000	HYDRAULIC EXPENSES	HYEX	Hydro O&M Expense	SG-P	2,252	35	586	178	329	991	133	1	0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5370000 Total					**2,252**	**35**	**586**	**178**	**329**	**991**	**133**	**1**	**0**
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-P	567	9	148	45	83	250	33	0	0
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-U	124	2	32	10	18	55	7	0	0
5371000 Total					**691**	**11**	**180**	**55**	**101**	**304**	**41**	**0**	**0**
5372000	HYDRO/HATCHERY EXP	HYEX	Hydro O&M Expense	SG-P	431	7	112	34	63	190	25	0	0
5372000 Total					**431**	**7**	**112**	**34**	**63**	**190**	**25**	**0**	**0**
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-P	196	3	51	15	29	86	12	0	0
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-U	31	0	8	2	5	14	2	0	0
5374000 Total					**227**	**3**	**59**	**18**	**33**	**100**	**13**	**0**	**0**
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-P	627	10	163	50	92	276	37	0	0
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-U	213	3	56	17	31	94	13	0	0
5379000 Total					**841**	**13**	**219**	**66**	**123**	**370**	**50**	**0**	**0**
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-P	12,330	189	3,209	973	1,803	5,425	727	3	0
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-U	7,222	111	1,879	570	1,056	3,178	426	2	0
5390000 Total					**19,552**	**300**	**5,088**	**1,543**	**2,860**	**8,603**	**1,153**	**6**	**0**
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-P	1,260	19	328	99	184	555	74	0	0
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-U	54	1	14	4	8	24	3	0	0
5400000 Total					**1,314**	**20**	**342**	**104**	**192**	**578**	**77**	**0**	**0**
5410000	MNT SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	0	0	0	0	0	0	0	0	0
5410000 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-P	487	7	127	38	71	214	29	0	0
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-U	26	0	7	2	4	12	2	0	0
5420000 Total					**514**	**8**	**134**	**41**	**75**	**226**	**30**	**0**	**0**
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-P	942	14	245	74	138	414	56	0	0
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-U	630	10	164	50	92	277	37	0	0
5430000 Total					**1,572**	**24**	**409**	**124**	**230**	**691**	**93**	**0**	**0**
5440000	MAINT OF ELEC PLNT	HYEX	Hydro O&M Expense	SG-U	66	1	17	5	10	29	4	0	0
5440000 Total					**66**	**1**	**17**	**5**	**10**	**29**	**4**	**0**	**0**
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-P	1,003	15	261	79	147	441	59	0	0
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-U	105	2	27	8	15	46	6	0	0
5441000 Total					**1,108**	**17**	**288**	**87**	**162**	**488**	**65**	**0**	**0**
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-P	698	11	182	55	102	307	41	0	0
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-U	122	2	32	10	18	54	7	0	0
5442000 Total					**820**	**13**	**213**	**65**	**120**	**361**	**48**	**0**	**0**
5450000	MNT MISC HYDRO PLT	HYEX	Hydro O&M Expense	SG-P	12	0	3	1	2	5	1	0	0
5450000 Total					**12**	**0**	**3**	**1**	**2**	**5**	**1**	**0**	**0**
5451000	MNT-FISH/WILDLIFE	HYEX	Hydro O&M Expense	SG-P	1,066	16	277	84	156	469	63	0	0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5451000 Total					**1,066**	**16**	**277**	**84**	**156**	**469**	**63**	**0**	**0**
5454000	MAINT-OTH REC FAC	HYEX	Hydro O&M Expense	SG-P	1	0	0	0	0	0	0	0	0
5454000 Total					**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-P	900	14	234	71	132	396	53	0	0
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-U	383	6	100	30	56	168	23	0	0
5455000 Total					**1,283**	**20**	**334**	**101**	**188**	**564**	**76**	**0**	**0**
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-P	1,325	20	345	105	194	583	78	0	0
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-U	323	5	84	26	47	142	19	0	0
5459000 Total					**1,648**	**25**	**429**	**130**	**241**	**725**	**97**	**0**	**0**
5459500	MAINT OF HYDRO PLT-E	HYEX	Hydro O&M Expense	SG-P	63	1	16	5	9	28	4	0	0
5459500 Total					**63**	**1**	**16**	**5**	**9**	**28**	**4**	**0**	**0**
5460000	OPER SUPERV & ENG	OPEX	Other Production O&M Expense	SG	280	4	73	22	41	123	17	0	0
5460000 Total					**280**	**4**	**73**	**22**	**41**	**123**	**17**	**0**	**0**
5471000	NATURAL GAS	NPCX	Net Power Cost Expense	SE	269,500	3,920	67,648	20,260	43,066	116,845	17,673	88	0
5471000 Total					**269,500**	**3,920**	**67,648**	**20,260**	**43,066**	**116,845**	**17,673**	**88**	**0**
5480000	GENERATION EXP	OPEX	Other Production O&M Expense	SG	17,771	273	4,624	1,402	2,599	7,819	1,048	5	0
5480000 Total					**17,771**	**273**	**4,624**	**1,402**	**2,599**	**7,819**	**1,048**	**5**	**0**
5490000	MIS OTH PWR GEN EX	OPEX	Other Production O&M Expense	OR	96	0	96	0	0	0	0	0	0
5490000	MIS OTH PWR GEN EX	OPEX	Other Production O&M Expense	SG	5,113	79	1,330	404	748	2,250	302	1	0
5490000 Total					**5,209**	**79**	**1,427**	**404**	**748**	**2,250**	**302**	**1**	**0**
5500000	RENTS (OTHER GEN)	OPEX	Other Production O&M Expense	OR	288	0	288	0	0	0	0	0	0
5500000	RENTS (OTHER GEN)	OPEX	Other Production O&M Expense	SG	3,646	56	949	288	533	1,604	215	1	0
5500000 Total					**3,934**	**56**	**1,237**	**288**	**533**	**1,604**	**215**	**1**	**0**
5520000	MAINT OF STRUCTURE	OPEX	Other Production O&M Expense	SG	2,930	45	762	231	429	1,289	173	1	0
5520000 Total					**2,930**	**45**	**762**	**231**	**429**	**1,289**	**173**	**1**	**0**
5530000	MNT GEN & ELEC PLT	OPEX	Other Production O&M Expense	SG	14,696	226	3,824	1,160	2,149	6,466	867	4	0
5530000 Total					**14,696**	**226**	**3,824**	**1,160**	**2,149**	**6,466**	**867**	**4**	**0**
5540000	MNT MSC OTH PWR GN	OPEX	Other Production O&M Expense	SG	1,178	18	307	93	172	518	69	0	0
5540000 Total					**1,178**	**18**	**307**	**93**	**172**	**518**	**69**	**0**	**0**
5546000	MISC PLANT EQUIP	OPEX	Other Production O&M Expense	SG	65	1	17	5	10	29	4	0	0
5546000 Total					**65**	**1**	**17**	**5**	**10**	**29**	**4**	**0**	**0**
5549500	MAINT OF OTH PWR PLT	OPEX	Other Production O&M Expense	SG	1,825	28	475	144	267	803	108	1	0
5549500	MAINT OF OTH PWR PLT	OPEX	Other Production O&M Expense	SG	0	0	0	0	0	0	0	0	0
5549500 Total					**1,825**	**28**	**475**	**144**	**267**	**803**	**108**	**1**	**0**
5552300	WA REC COMPLIANCE	NPCX	Net Power Cost Expense	OTHER	5	0	0	0	0	0	0	0	5
5552300 Total					**5**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5**
5552400	RENEW ENRGY CR PURCH	NPCX	Net Power Cost Expense	OTHER	786	0	0	0	0	0	0	0	786

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5552400 Total					**786**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**786**
5552500	OTH/INT/REC/DEL	NPCX	Net Power Cost Expense	SE	12	0	3	1	2	5	1	0	0
5552500 Total					**12**	**0**	**3**	**1**	**2**	**5**	**1**	**0**	**0**
5552700	PURCH POWER-UT SITUS	NPCX	Net Power Cost Expense	UT	3,756	0	0	0	0	3,756	0	0	0
5552700 Total					**3,756**	**0**	**0**	**0**	**0**	**3,756**	**0**	**0**	**0**
5555700	NPC Deferral Mchnsm	NPCX	Net Power Cost Expense	OTHER	-69,933	0	0	0	0	0	0	0	-69,933
5555700 Total					**-69,933**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-69,933**
5555900	Short-Term Firm Whls	NPCX	Net Power Cost Expense	SG	559,846	8,603	145,687	44,183	81,879	246,318	33,017	159	0
5555900 Total					**559,846**	**8,603**	**145,687**	**44,183**	**81,879**	**246,318**	**33,017**	**159**	**0**
5556100	BOOKOUTS NETTED-LOSS	NPCX	Net Power Cost Expense	SG	88,834	1,365	23,117	7,011	12,992	39,085	5,239	25	0
5556100 Total					**88,834**	**1,365**	**23,117**	**7,011**	**12,992**	**39,085**	**5,239**	**25**	**0**
5556200	TRADING NETTED-LOSS	NPCX	Net Power Cost Expense	SG	-16	0	-4	-1	-2	-7	-1	0	0
5556200 Total					**-16**	**0**	**-4**	**-1**	**-2**	**-7**	**-1**	**0**	**0**
5556300	FIRM ENERGY PURCH	NPCX	Net Power Cost Expense	SG	391,828	6,021	101,964	30,923	57,306	172,394	23,108	111	0
5556300 Total					**391,828**	**6,021**	**101,964**	**30,923**	**57,306**	**172,394**	**23,108**	**111**	**0**
5556400	FIRM DEMAND PURCH	NPCX	Net Power Cost Expense	SG	41,486	638	10,796	3,274	6,067	18,253	2,447	12	0
5556400 Total					**41,486**	**638**	**10,796**	**3,274**	**6,067**	**18,253**	**2,447**	**12**	**0**
5556700	POST-MERG FIRM PUR	NPCX	Net Power Cost Expense	SG	-287,355	-4,416	-74,777	-22,678	-42,027	-126,429	-16,947	-81	0
5556700 Total					**-287,355**	**-4,416**	**-74,777**	**-22,678**	**-42,027**	**-126,429**	**-16,947**	**-81**	**0**
5556710	EIM - FIRM PURCHASES	NPCX	Net Power Cost Expense	SG	-65,401	-1,005	-17,019	-5,161	-9,565	-28,775	-3,857	-19	0
5556710 Total					**-65,401**	**-1,005**	**-17,019**	**-5,161**	**-9,565**	**-28,775**	**-3,857**	**-19**	**0**
5560000	SYS CTRL & LD DISP	PSEX	Power Supply Expense	SG	910	14	237	72	133	400	54	0	0
5560000 Total					**910**	**14**	**237**	**72**	**133**	**400**	**54**	**0**	**0**
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SE	9	0	2	1	1	4	1	0	0
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SG	35,879	551	9,337	2,832	5,247	15,786	2,116	10	0
5570000 Total					**35,888**	**551**	**9,339**	**2,832**	**5,249**	**15,790**	**2,117**	**10**	**0**
5579000	OTH EXP-ST SITUS ACT	PSEX	Power Supply Expense	IDU	3,757	0	0	0	0	0	3,757	0	0
5579000	OTH EXP-ST SITUS ACT	PSEX	Power Supply Expense	OR	1,683	0	1,683	0	0	0	0	0	0
5579000 Total					**5,440**	**0**	**1,683**	**0**	**0**	**0**	**3,757**	**0**	**0**
5579100	OTH EXP-LIQ DAMAGE	PSEX	Power Supply Expense	UT	24	0	0	0	0	24	0	0	0
5579100	OTH EXP-LIQ DAMAGE	PSEX	Power Supply Expense	WYU	65	0	0	0	65	0	0	0	0
5579100 Total					**89**	**0**	**0**	**0**	**65**	**24**	**0**	**0**	**0**
5600000	OPER SUPERV & ENG	TNEX	Transmission O&M Expense	SG	7,289	112	1,897	575	1,066	3,207	430	2	0
5600000 Total					**7,289**	**112**	**1,897**	**575**	**1,066**	**3,207**	**430**	**2**	**0**
5612000	LD - MONITOR & OPER	TNEX	Transmission O&M Expense	SG	7,353	113	1,913	580	1,075	3,235	434	2	0
5612000 Total					**7,353**	**113**	**1,913**	**580**	**1,075**	**3,235**	**434**	**2**	**0**
5614000	SCHED, SYS CTR & DSP	TNEX	Transmission O&M Expense	SG	435	7	113	34	64	192	26	0	0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5614000 Total					**435**	**7**	**113**	**34**	**64**	**192**	**26**	**0**	**0**
5614010	EIM - SCHEDULING,SYS	TNEX	Transmission O&M Expense	SG	898	14	234	71	131	395	53	0	0
5614010 Total					**898**	**14**	**234**	**71**	**131**	**395**	**53**	**0**	**0**
5615000	REL PLAN & STDS DEV	TNEX	Transmission O&M Expense	SG	1,905	29	496	150	279	838	112	1	0
5615000 Total					**1,905**	**29**	**496**	**150**	**279**	**838**	**112**	**1**	**0**
5616000	TRANS SVC STUDIES	TNEX	Transmission O&M Expense	SG	123	2	32	10	18	54	7	0	0
5616000 Total					**123**	**2**	**32**	**10**	**18**	**54**	**7**	**0**	**0**
5617000	GEN INTERCNCT STUD	TNEX	Transmission O&M Expense	SG	1,072	16	279	85	157	472	63	0	0
5617000 Total					**1,072**	**16**	**279**	**85**	**157**	**472**	**63**	**0**	**0**
5618000	REL PLN & STAND SVCS	TNEX	Transmission O&M Expense	SG	8,211	126	2,137	648	1,201	3,613	484	2	0
5618000 Total					**8,211**	**126**	**2,137**	**648**	**1,201**	**3,613**	**484**	**2**	**0**
5620000	STATION EXP(TRANS)	TNEX	Transmission O&M Expense	SG	2,789	43	726	220	408	1,227	164	1	0
5620000 Total					**2,789**	**43**	**726**	**220**	**408**	**1,227**	**164**	**1**	**0**
5630000	OVERHEAD LINE EXP	TNEX	Transmission O&M Expense	SG	1,038	16	270	82	152	457	61	0	0
5630000 Total					**1,038**	**16**	**270**	**82**	**152**	**457**	**61**	**0**	**0**
5650000	TRNS ELEC BY OTHRS	NPCX	Net Power Cost Expense	SG	188	3	49	15	28	83	11	0	0
5650000 Total					**188**	**3**	**49**	**15**	**28**	**83**	**11**	**0**	**0**
5650010	EIM - TRANSM OF ELEC	NPCX	Net Power Cost Expense	SG	2,138	33	556	169	313	940	126	1	0
5650010 Total					**2,138**	**33**	**556**	**169**	**313**	**940**	**126**	**1**	**0**
5651000	S/T FIRM WHEELING	NPCX	Net Power Cost Expense	SG	14,088	216	3,666	1,112	2,060	6,198	831	4	0
5651000 Total					**14,088**	**216**	**3,666**	**1,112**	**2,060**	**6,198**	**831**	**4**	**0**
5652500	NON-FIRM WHEEL EXP	NPCX	Net Power Cost Expense	SE	-1,671	-24	-419	-126	-267	-724	-110	-1	0
5652500 Total					**-1,671**	**-24**	**-419**	**-126**	**-267**	**-724**	**-110**	**-1**	**0**
5654600	POST-MRG WHEEL EXP	NPCX	Net Power Cost Expense	SG	126,586	1,945	32,941	9,990	18,514	55,695	7,465	36	0
5654600 Total					**126,586**	**1,945**	**32,941**	**9,990**	**18,514**	**55,695**	**7,465**	**36**	**0**
5660000	MISC TRANS EXPENSE	TNEX	Transmission O&M Expense	SG	2,863	44	745	226	419	1,260	169	1	0
5660000 Total					**2,863**	**44**	**745**	**226**	**419**	**1,260**	**169**	**1**	**0**
5660010	MISC TRANS EXPENSE	TNEX	Transmission O&M Expense	SG	9	0	2	1	1	4	1	0	0
5660010 Total					**9**	**0**	**2**	**1**	**1**	**4**	**1**	**0**	**0**
5670000	RENTS-TRANSMISSION	TNEX	Transmission O&M Expense	SG	2,121	33	552	167	310	933	125	1	0
5670000 Total					**2,121**	**33**	**552**	**167**	**310**	**933**	**125**	**1**	**0**
5680000	MNT SUPERV & ENG	TNEX	Transmission O&M Expense	SG	1,350	21	351	107	198	594	80	0	0
5680000 Total					**1,350**	**21**	**351**	**107**	**198**	**594**	**80**	**0**	**0**
5690000	MAINT OF STRUCTURE	TNEX	Transmission O&M Expense	SG	84	1	22	7	12	37	5	0	0
5690000 Total					**84**	**1**	**22**	**7**	**12**	**37**	**5**	**0**	**0**
5691000	MAINT-COMP HW TRANS	TNEX	Transmission O&M Expense	SG	7	0	2	1	1	3	0	0	0
5691000 Total					**7**	**0**	**2**	**1**	**1**	**3**	**0**	**0**	**0**

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5692000	MAINT-COMP SW TRANS	TNEX	Transmission O&M Expense	SG	849	13	221	67	124	374	50	0	0
5692000 Total					**849**	**13**	**221**	**67**	**124**	**374**	**50**	**0**	**0**
5693000	MAINT-COM EQP TRANS	TNEX	Transmission O&M Expense	SG	4,867	75	1,267	384	712	2,141	287	1	0
5693000 Total					**4,867**	**75**	**1,267**	**384**	**712**	**2,141**	**287**	**1**	**0**
5700000	MAINT STATION EQIP	TNEX	Transmission O&M Expense	SG	11,856	182	3,085	936	1,734	5,216	699	3	0
5700000 Total					**11,856**	**182**	**3,085**	**936**	**1,734**	**5,216**	**699**	**3**	**0**
5710000	MAINT OVHD LINES	TNEX	Transmission O&M Expense	SG	16,156	248	4,204	1,275	2,363	7,108	953	5	0
5710000 Total					**16,156**	**248**	**4,204**	**1,275**	**2,363**	**7,108**	**953**	**5**	**0**
5720000	MNT UNDERGRD LINES	TNEX	Transmission O&M Expense	SG	38	1	10	3	6	17	2	0	0
5720000 Total					**38**	**1**	**10**	**3**	**6**	**17**	**2**	**0**	**0**
5730000	MNT MSC TRANS PLNT	TNEX	Transmission O&M Expense	SG	151	2	39	12	22	66	9	0	0
5730000 Total					**151**	**2**	**39**	**12**	**22**	**66**	**9**	**0**	**0**
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	CA	47	47	0	0	0	0	0	0	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	31	0	0	0	0	0	31	0	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	OR	309	0	309	0	0	0	0	0	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	7,995	290	2,139	492	818	3,848	408	0	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	UT	424	0	0	0	0	424	0	0	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WA	133	0	0	133	0	0	0	0	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	105	0	0	0	105	0	0	0	0
5800000 Total					**9,045**	**337**	**2,448**	**624**	**924**	**4,272**	**439**	**0**	**0**
5810000	LOAD DISPATCHING	DNEX	Distribution O&M Expense	SNPD	12,175	441	3,258	748	1,246	5,860	622	0	0
5810000 Total					**12,175**	**441**	**3,258**	**748**	**1,246**	**5,860**	**622**	**0**	**0**
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	CA	76	76	0	0	0	0	0	0	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	IDU	595	0	0	0	0	0	595	0	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	OR	1,050	0	1,050	0	0	0	0	0	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	SNPD	4	0	1	0	0	2	0	0	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	UT	1,946	0	0	0	0	1,946	0	0	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WA	297	0	0	297	0	0	0	0	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WYP	710	0	0	0	710	0	0	0	0
5820000 Total					**4,678**	**77**	**1,051**	**297**	**710**	**1,948**	**595**	**0**	**0**
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	CA	244	244	0	0	0	0	0	0	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	IDU	377	0	0	0	0	0	377	0	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	OR	1,650	0	1,650	0	0	0	0	0	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	SNPD	0	0	0	0	0	0	0	0	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	UT	5,928	0	0	0	0	5,928	0	0	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WA	232	0	0	232	0	0	0	0	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYP	516	0	0	0	516	0	0	0	0

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5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYU	139	0	0	0	139	0	0	0	0
5830000 Total					**9,086**	**244**	**1,650**	**232**	**656**	**5,928**	**377**	**0**	**0**
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	OR	0	0	0	0	0	0	0	0	0
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	UT	1	0	0	0	0	1	0	0	0
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	WYP	0	0	0	0	0	0	0	0	0
5840000 Total					**2**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**0**
5850000	STRT LGHT-SGNL SYS	DNEX	Distribution O&M Expense	SNPD	213	8	57	13	22	102	11	0	0
5850000 Total					**213**	**8**	**57**	**13**	**22**	**102**	**11**	**0**	**0**
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	CA	82	82	0	0	0	0	0	0	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	IDU	195	0	0	0	0	0	195	0	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	OR	741	0	741	0	0	0	0	0	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	UT	844	0	0	0	0	844	0	0	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WA	306	0	0	306	0	0	0	0	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYP	346	0	0	0	346	0	0	0	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYU	108	0	0	0	108	0	0	0	0
5860000 Total					**2,625**	**82**	**741**	**306**	**455**	**844**	**195**	**0**	**0**
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	CA	596	596	0	0	0	0	0	0	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	IDU	862	0	0	0	0	0	862	0	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	OR	5,498	0	5,498	0	0	0	0	0	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	UT	5,267	0	0	0	0	5,267	0	0	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WA	1,298	0	0	1,298	0	0	0	0	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYP	1,119	0	0	0	1,119	0	0	0	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYU	137	0	0	0	137	0	0	0	0
5870000 Total					**14,777**	**596**	**5,498**	**1,298**	**1,256**	**5,267**	**862**	**0**	**0**
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	CA	32	32	0	0	0	0	0	0	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	IDU	-15	0	0	0	0	0	-15	0	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	OR	78	0	78	0	0	0	0	0	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	SNPD	871	32	233	54	89	419	44	0	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	UT	-75	0	0	0	0	-75	0	0	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WA	-16	0	0	-16	0	0	0	0	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYP	-113	0	0	0	-113	0	0	0	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYU	-75	0	0	0	-75	0	0	0	0
5880000 Total					**687**	**64**	**311**	**37**	**-99**	**345**	**30**	**0**	**0**
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	CA	60	60	0	0	0	0	0	0	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	IDU	39	0	0	0	0	0	39	0	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	OR	1,590	0	1,590	0	0	0	0	0	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	SNPD	13	0	3	1	1	6	1	0	0

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5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	UT	437	0	0	0	0	437	0	0	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WA	145	0	0	145	0	0	0	0	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYP	488	0	0	0	488	0	0	0	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYU	87	0	0	0	87	0	0	0	0
5890000 Total					**2,860**	**60**	**1,594**	**146**	**576**	**443**	**40**	**0**	**0**
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	CA	125	125	0	0	0	0	0	0	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	148	0	0	0	0	0	148	0	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	OR	949	0	949	0	0	0	0	0	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	2,489	90	666	153	255	1,198	127	0	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	UT	1,486	0	0	0	0	1,486	0	0	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WA	210	0	0	210	0	0	0	0	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	533	0	0	0	533	0	0	0	0
5900000 Total					**5,940**	**216**	**1,615**	**363**	**788**	**2,684**	**275**	**0**	**0**
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	CA	47	47	0	0	0	0	0	0	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	IDU	127	0	0	0	0	0	127	0	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	OR	439	0	439	0	0	0	0	0	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	SNPD	181	7	48	11	19	87	9	0	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	UT	956	0	0	0	0	956	0	0	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WA	121	0	0	121	0	0	0	0	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYP	389	0	0	0	389	0	0	0	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYU	71	0	0	0	71	0	0	0	0
5910000 Total					**2,330**	**53**	**487**	**132**	**479**	**1,043**	**136**	**0**	**0**
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	CA	231	231	0	0	0	0	0	0	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	IDU	264	0	0	0	0	0	264	0	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	OR	2,645	0	2,645	0	0	0	0	0	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	SNPD	1,853	67	496	114	190	892	95	0	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	UT	3,337	0	0	0	0	3,337	0	0	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WA	280	0	0	280	0	0	0	0	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYP	988	0	0	0	988	0	0	0	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYU	96	0	0	0	96	0	0	0	0
5920000 Total					**9,695**	**298**	**3,141**	**394**	**1,273**	**4,229**	**359**	**0**	**0**
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	CA	11,384	11,384	0	0	0	0	0	0	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	IDU	3,355	0	0	0	0	0	3,355	0	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	OR	30,124	0	30,124	0	0	0	0	0	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	SNPD	2,198	80	588	135	225	1,058	112	0	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	UT	31,804	0	0	0	0	31,804	0	0	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WA	5,403	0	0	5,403	0	0	0	0	0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYP	5,462	0	0	0	5,462	0	0	0	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYU	809	0	0	0	809	0	0	0	0
5930000 Total					**90,538**	**11,464**	**30,712**	**5,539**	**6,496**	**32,861**	**3,467**	**0**	**0**
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	CA	-361	-361	0	0	0	0	0	0	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	IDU	243	0	0	0	0	0	243	0	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	OR	-2,146	0	-2,146	0	0	0	0	0	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	UT	1,305	0	0	0	0	1,305	0	0	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WA	-217	0	0	-217	0	0	0	0	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WYP	-58	0	0	0	-58	0	0	0	0
5931000 Total					**-1,233**	**-361**	**-2,146**	**-217**	**-58**	**1,305**	**243**	**0**	**0**
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	CA	440	440	0	0	0	0	0	0	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	IDU	865	0	0	0	0	0	865	0	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	OR	6,235	0	6,235	0	0	0	0	0	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	SNPD	25	1	7	2	3	12	1	0	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	UT	14,954	0	0	0	0	14,954	0	0	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WA	1,201	0	0	1,201	0	0	0	0	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYP	1,809	0	0	0	1,809	0	0	0	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYU	246	0	0	0	246	0	0	0	0
5940000 Total					**25,774**	**441**	**6,242**	**1,202**	**2,058**	**14,965**	**867**	**0**	**0**
5950000	MAINT LINE TRNSFRM	DNEX	Distribution O&M Expense	SNPD	958	35	256	59	98	461	49	0	0
5950000 Total					**958**	**35**	**256**	**59**	**98**	**461**	**49**	**0**	**0**
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	CA	82	82	0	0	0	0	0	0	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	IDU	94	0	0	0	0	0	94	0	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	OR	850	0	850	0	0	0	0	0	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	UT	1,272	0	0	0	0	1,272	0	0	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WA	141	0	0	141	0	0	0	0	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYP	355	0	0	0	355	0	0	0	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYU	114	0	0	0	114	0	0	0	0
5960000 Total					**2,908**	**82**	**850**	**141**	**469**	**1,272**	**94**	**0**	**0**
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	CA	20	20	0	0	0	0	0	0	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	IDU	40	0	0	0	0	0	40	0	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	OR	259	0	259	0	0	0	0	0	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	SNPD	-265	-10	-71	-16	-27	-128	-14	0	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	UT	240	0	0	0	0	240	0	0	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WA	32	0	0	32	0	0	0	0	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYP	36	0	0	0	36	0	0	0	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYU	14	0	0	0	14	0	0	0	0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5970000 Total					**376**	**11**	**188**	**16**	**23**	**113**	**27**	**0**	**0**
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	CA	69	69	0	0	0	0	0	0	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	IDU	83	0	0	0	0	0	83	0	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	OR	620	0	620	0	0	0	0	0	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	SNPD	3,397	123	909	209	348	1,635	173	0	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	UT	672	0	0	0	0	672	0	0	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WA	128	0	0	128	0	0	0	0	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYP	185	0	0	0	185	0	0	0	0
5980000 Total					**5,153**	**192**	**1,529**	**336**	**533**	**2,308**	**256**	**0**	**0**
5989500	MNT DIST PLNT-ENV AM	DNEX	Distribution O&M Expense	SNPD	2,251	82	602	138	230	1,084	115	0	0
5989500 Total					**2,251**	**82**	**602**	**138**	**230**	**1,084**	**115**	**0**	**0**
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	CN	2,689	64	840	187	200	1,286	113	0	0
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	WYP	0	0	0	0	0	0	0	0	0
9010000 Total					**2,690**	**64**	**840**	**187**	**200**	**1,286**	**113**	**0**	**0**
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CA	659	659	0	0	0	0	0	0	0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CN	744	18	232	52	55	356	31	0	0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	IDU	2,185	0	0	0	0	0	2,185	0	0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	OR	7,224	0	7,224	0	0	0	0	0	0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	UT	4,462	0	0	0	0	4,462	0	0	0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WA	642	0	0	642	0	0	0	0	0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYP	1,080	0	0	0	1,080	0	0	0	0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYU	227	0	0	0	227	0	0	0	0
9020000 Total					**17,222**	**677**	**7,456**	**694**	**1,362**	**4,817**	**2,216**	**0**	**0**
9030000	CUST RCRD/COLL EXP	CAEX	Customer Accounting Expense	CN	1,085	26	339	75	81	519	46	0	0
9030000 Total					**1,085**	**26**	**339**	**75**	**81**	**519**	**46**	**0**	**0**
9031000	CUST RCRD/CUST SYS	CAEX	Customer Accounting Expense	CN	2,019	48	630	140	150	966	85	0	0
9031000	CUST RCRD/CUST SYS	CAEX	Customer Accounting Expense	OR	51	0	51	0	0	0	0	0	0
9031000 Total					**2,070**	**48**	**681**	**140**	**150**	**966**	**85**	**0**	**0**
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	CA	0	0	0	0	0	0	0	0	0
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	CN	8,996	216	2,808	624	668	4,302	378	0	0
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	UT	-4	0	0	0	0	-4	0	0	0
9032000 Total					**8,991**	**216**	**2,808**	**624**	**668**	**4,298**	**378**	**0**	**0**
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CA	169	169	0	0	0	0	0	0	0
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CN	14,667	352	4,579	1,017	1,089	7,015	616	0	0
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	IDU	367	0	0	0	0	0	367	0	0
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	OR	1,550	0	1,550	0	0	0	0	0	0
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	UT	3,140	0	0	0	0	3,140	0	0	0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WA	516	0	0	516	0	0	0	0	0
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYP	467	0	0	0	467	0	0	0	0
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYU	81	0	0	0	81	0	0	0	0
9033000 Total					**20,956**	**520**	**6,129**	**1,533**	**1,636**	**10,154**	**983**	**0**	**0**
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	CA	10	10	0	0	0	0	0	0	0
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	IDU	23	0	0	0	0	0	23	0	0
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	OR	122	0	122	0	0	0	0	0	0
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	UT	75	0	0	0	0	75	0	0	0
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WA	14	0	0	14	0	0	0	0	0
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYP	16	0	0	0	16	0	0	0	0
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYU	5	0	0	0	5	0	0	0	0
9035000 Total					**264**	**10**	**122**	**14**	**21**	**75**	**23**	**0**	**0**
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	CN	14,974	359	4,674	1,039	1,111	7,161	629	0	0
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	OR	22	0	22	0	0	0	0	0	0
9036000 Total					**14,996**	**359**	**4,696**	**1,039**	**1,111**	**7,161**	**629**	**0**	**0**
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CA	712	712	0	0	0	0	0	0	0
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CN	64	2	20	4	5	31	3	0	0
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	IDU	718	0	0	0	0	0	718	0	0
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	OR	4,700	0	4,700	0	0	0	0	0	0
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	UT	4,558	0	0	0	0	4,558	0	0	0
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WA	1,670	0	0	1,670	0	0	0	0	0
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WYP	999	0	0	0	999	0	0	0	0
9040000 Total					**13,421**	**714**	**4,720**	**1,674**	**1,004**	**4,589**	**721**	**0**	**0**
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	CA	20	20	0	0	0	0	0	0	0
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	IDU	0	0	0	0	0	0	0	0	0
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	OR	-69	0	-69	0	0	0	0	0	0
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	UT	-29	0	0	0	0	-29	0	0	0
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WA	0	0	0	0	0	0	0	0	0
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WYP	-6	0	0	0	-6	0	0	0	0
9042000 Total					**-84**	**20**	**-69**	**0**	**-6**	**-29**	**0**	**0**	**0**
9050000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	CN	22	1	7	2	2	11	1	0	0
9050000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	UT	417	0	0	0	0	417	0	0	0
9050000 Total					**439**	**1**	**7**	**2**	**2**	**427**	**1**	**0**	**0**
9070000	SUPRV (CUST SERV)	CSEX	Customer Service Expense	CN	0	0	0	0	0	0	0	0	0
9070000 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	CA	38	38	0	0	0	0	0	0	0
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	CN	9	0	3	1	1	4	0	0	0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	OR	1	0	1	0	0	0	0	0	0
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	UT	5	0	0	0	0	5	0	0	0
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	WA	8	0	0	8	0	0	0	0	0
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	WYP	1	0	0	0	1	0	0	0	0
9080000 Total					**63**	**38**	**4**	**9**	**2**	**9**	**0**	**0**	**0**
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	CA	33	33	0	0	0	0	0	0	0
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	CN	867	21	271	60	64	415	36	0	0
9081000 Total					**900**	**54**	**271**	**60**	**64**	**415**	**36**	**0**	**0**
9084000	DSM DIRECT	CSEX	Customer Service Expense	CA	37	37	0	0	0	0	0	0	0
9084000	DSM DIRECT	CSEX	Customer Service Expense	CN	1,285	31	401	89	95	614	54	0	0
9084000	DSM DIRECT	CSEX	Customer Service Expense	IDU	0	0	0	0	0	0	0	0	0
9084000	DSM DIRECT	CSEX	Customer Service Expense	OTHER	99	0	0	0	0	0	0	0	99
9084000	DSM DIRECT	CSEX	Customer Service Expense	UT	7	0	0	0	0	7	0	0	0
9084000	DSM DIRECT	CSEX	Customer Service Expense	WA	7	0	0	7	0	0	0	0	0
9084000	DSM DIRECT	CSEX	Customer Service Expense	WYP	-2	0	0	0	-2	0	0	0	0
9084000 Total					**1,432**	**68**	**401**	**96**	**94**	**621**	**54**	**0**	**99**
9085000	DSM AMORT	CSEX	Customer Service Expense	WYP	2	0	0	0	2	0	0	0	0
9085000 Total					**2**	**0**	**0**	**0**	**2**	**0**	**0**	**0**	**0**
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	OTHER	69,327	0	0	0	0	0	0	0	69,327
9085100 Total					**69,327**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**69,327**
9086000	CUST SERV	CSEX	Customer Service Expense	CA	0	0	0	0	0	0	0	0	0
9086000	CUST SERV	CSEX	Customer Service Expense	CN	540	13	169	37	40	258	23	0	0
9086000	CUST SERV	CSEX	Customer Service Expense	IDU	17	0	0	0	0	0	17	0	0
9086000	CUST SERV	CSEX	Customer Service Expense	OR	2,095	0	2,095	0	0	0	0	0	0
9086000	CUST SERV	CSEX	Customer Service Expense	UT	2,447	0	0	0	0	2,447	0	0	0
9086000	CUST SERV	CSEX	Customer Service Expense	WA	340	0	0	340	0	0	0	0	0
9086000	CUST SERV	CSEX	Customer Service Expense	WYP	968	0	0	0	968	0	0	0	0
9086000 Total					**6,409**	**13**	**2,264**	**378**	**1,008**	**2,706**	**40**	**0**	**0**
9089500	BLUE SKY EXPENSE	CSEX	Customer Service Expense	OTHER	3,944	0	0	0	0	0	0	0	3,944
9089500 Total					**3,944**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3,944**
9089600	SOLAR FEED-IN EXP	CSEX	Customer Service Expense	OTHER	9,987	0	0	0	0	0	0	0	9,987
9089600 Total					**9,987**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**9,987**
9089700	SUBSCRIBER SOLAR	CSEX	Customer Service Expense	UT	125	0	0	0	0	125	0	0	0
9089700 Total					**125**	**0**	**0**	**0**	**0**	**125**	**0**	**0**	**0**
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CA	147	147	0	0	0	0	0	0	0
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CN	2,687	64	839	186	199	1,285	113	0	0
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	IDU	161	0	0	0	0	0	161	0	0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	OR	1,894	0	1,894	0	0	0	0	0	0
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	UT	1,553	0	0	0	0	1,553	0	0	0
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WA	273	0	0	273	0	0	0	0	0
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WYP	369	0	0	0	369	0	0	0	0
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WYU	3	0	0	0	3	0	0	0	0
9090000 Total					**7,087**	**212**	**2,733**	**459**	**571**	**2,838**	**274**	**0**	**0**
9100000	MISC CUST SERV/INF	CSEX	Customer Service Expense	CN	5	0	2	0	0	2	0	0	0
9100000 Total					**5**	**0**	**2**	**0**	**0**	**2**	**0**	**0**	**0**
9101000	MISC CUST SERV/INF	CSEX	Customer Service Expense	CN	11	0	3	1	1	5	0	0	0
9101000 Total					**11**	**0**	**3**	**1**	**1**	**5**	**0**	**0**	**0**
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	OR	0	0	0	0	0	0	0	0	0
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	SO	73,781	1,647	20,080	5,680	10,032	32,094	4,234	15	0
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	WA	0	0	0	0	0	0	0	0	0
9200000 Total					**73,781**	**1,647**	**20,080**	**5,680**	**10,032**	**32,094**	**4,234**	**15**	**0**
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	CA	5	5	0	0	0	0	0	0	0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	CN	89	2	28	6	7	43	4	0	0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	IDU	26	0	0	0	0	0	26	0	0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	OR	57	0	57	0	0	0	0	0	0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	SO	9,148	204	2,490	704	1,244	3,979	525	2	0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	UT	128	0	0	0	0	128	0	0	0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WA	10	0	0	10	0	0	0	0	0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYP	36	0	0	0	36	0	0	0	0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYU	8	0	0	0	8	0	0	0	0
9210000 Total					**9,508**	**211**	**2,574**	**720**	**1,295**	**4,150**	**555**	**2**	**0**
9220000	A&G EXP TRANSF-CR	AGEX	Administrative & General Expense	SO	-33,020	-737	-8,987	-2,542	-4,490	-14,363	-1,895	-7	0
9220000 Total					**-33,020**	**-737**	**-8,987**	**-2,542**	**-4,490**	**-14,363**	**-1,895**	**-7**	**0**
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	CA	129	129	0	0	0	0	0	0	0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	IDU	0	0	0	0	0	0	0	0	0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	OR	88	0	88	0	0	0	0	0	0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	SO	12,592	281	3,427	969	1,712	5,477	723	3	0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	UT	1,275	0	0	0	0	1,275	0	0	0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WA	10	0	0	10	0	0	0	0	0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYP	1	0	0	0	1	0	0	0	0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYU	6	0	0	0	6	0	0	0	0
9230000 Total					**14,099**	**410**	**3,515**	**979**	**1,719**	**6,752**	**723**	**3**	**0**
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	OR	36	0	36	0	0	0	0	0	0
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	SO	8,410	188	2,289	647	1,143	3,658	483	2	0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	UT	4	0	0	0	0	4	0	0	0
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	WYP	2	0	0	0	2	0	0	0	0
9239990 Total					**8,452**	**188**	**2,325**	**647**	**1,146**	**3,662**	**483**	**2**	**0**
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	IDU	114	0	0	0	0	0	114	0	0
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	OR	7,069	0	7,069	0	0	0	0	0	0
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	UT	2,152	0	0	0	0	2,152	0	0	0
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	WYP	350	0	0	0	350	0	0	0	0
9241000 Total					**9,684**	**0**	**7,069**	**0**	**350**	**2,152**	**114**	**0**	**0**
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	CA	1,468	1,468	0	0	0	0	0	0	0
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	OR	-773	0	-773	0	0	0	0	0	0
9242000 Total					**696**	**1,468**	**-773**	**0**	**0**	**0**	**0**	**0**	**0**
9243000	PROP INS - PREMIUMS	AGEX	Administrative & General Expense	SO	4,723	105	1,285	364	642	2,054	271	1	0
9243000 Total					**4,723**	**105**	**1,285**	**364**	**642**	**2,054**	**271**	**1**	**0**
9250000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	SO	17,292	386	4,706	1,331	2,351	7,522	992	4	0
9250000 Total					**17,292**	**386**	**4,706**	**1,331**	**2,351**	**7,522**	**992**	**4**	**0**
9251000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	OR	-22	0	-22	0	0	0	0	0	0
9251000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	SO	22	0	6	2	3	9	1	0	0
9251000 Total					**0**	**0**	**-16**	**2**	**3**	**9**	**1**	**0**	**0**
9261200	PEN EXP-OTH NBC	AGEX	Administrative & General Expense	SO	8,017	179	2,182	617	1,090	3,488	460	2	0
9261200 Total					**8,017**	**179**	**2,182**	**617**	**1,090**	**3,488**	**460**	**2**	**0**
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	CA	-45	-45	0	0	0	0	0	0	0
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	OR	-504	0	-504	0	0	0	0	0	0
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	SO	-3,097	-69	-843	-238	-421	-1,347	-178	-1	0
9261500 Total					**-3,645**	**-114**	**-1,346**	**-238**	**-421**	**-1,347**	**-178**	**-1**	**0**
9262200	POSTRET EXP-OTH NBC	AGEX	Administrative & General Expense	SO	-11,898	-266	-3,238	-916	-1,618	-5,176	-683	-2	0
9262200 Total					**-11,898**	**-266**	**-3,238**	**-916**	**-1,618**	**-5,176**	**-683**	**-2**	**0**
9262500	POSTRET EXP-ST SITUS	AGEX	Administrative & General Expense	CA	9	9	0	0	0	0	0	0	0
9262500	POSTRET EXP-ST SITUS	AGEX	Administrative & General Expense	OR	97	0	97	0	0	0	0	0	0
9262500	POSTRET EXP-ST SITUS	AGEX	Administrative & General Expense	WYP	375	0	0	0	375	0	0	0	0
9262500 Total					**481**	**9**	**97**	**0**	**375**	**0**	**0**	**0**	**0**
9263200	SERP EXP-OTH NBC	AGEX	Administrative & General Expense	SO	2,918	65	794	225	397	1,269	167	1	0
9263200 Total					**2,918**	**65**	**794**	**225**	**397**	**1,269**	**167**	**1**	**0**
9269100	GROSS-UP - PENSION	AGEX	Administrative & General Expense	SO	7,400	165	2,014	570	1,006	3,219	425	2	0
9269100 Total					**7,400**	**165**	**2,014**	**570**	**1,006**	**3,219**	**425**	**2**	**0**
9269200	GROSS-UP - POST-RETR	AGEX	Administrative & General Expense	SO	2,070	46	563	159	281	900	119	0	0
9269200 Total					**2,070**	**46**	**563**	**159**	**281**	**900**	**119**	**0**	**0**
9269300	GROSS-UP - SERP	AGEX	Administrative & General Expense	SO	25	1	7	2	3	11	1	0	0

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(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9269300 Total					**25**	**1**	**7**	**2**	**3**	**11**	**1**	**0**	**0**
9269400	GROSS-UP - MD/DN/V/L	AGEX	Administrative & General Expense	SO	61,452	1,371	16,724	4,731	8,355	26,731	3,527	13	0
9269400 Total					**61,452**	**1,371**	**16,724**	**4,731**	**8,355**	**26,731**	**3,527**	**13**	**0**
9269500	GROSS-UP - 401(K) EX	AGEX	Administrative & General Expense	SO	37,760	843	10,276	2,907	5,134	16,425	2,167	8	0
9269500 Total					**37,760**	**843**	**10,276**	**2,907**	**5,134**	**16,425**	**2,167**	**8**	**0**
9269600	GROSS-UP - POST-EMPL	AGEX	Administrative & General Expense	SO	6,681	149	1,818	514	908	2,906	383	1	0
9269600 Total					**6,681**	**149**	**1,818**	**514**	**908**	**2,906**	**383**	**1**	**0**
9269700	GROSS-UP - OTH BEN E	AGEX	Administrative & General Expense	SO	6,718	150	1,828	517	913	2,922	386	1	0
9269700 Total					**6,718**	**150**	**1,828**	**517**	**913**	**2,922**	**386**	**1**	**0**
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	CA	924	924	0	0	0	0	0	0	0
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	IDU	51	0	0	0	0	0	51	0	0
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	OR	585	0	585	0	0	0	0	0	0
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	SE	8	0	2	1	1	4	1	0	0
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	SO	3,155	70	859	243	429	1,372	181	1	0
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	UT	372	0	0	0	0	372	0	0	0
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WA	43	0	0	43	0	0	0	0	0
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WYP	56	0	0	0	56	0	0	0	0
9280000 Total					**5,193**	**994**	**1,445**	**286**	**486**	**1,748**	**232**	**1**	**0**
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	CA	134	134	0	0	0	0	0	0	0
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	IDU	644	0	0	0	0	0	644	0	0
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	OR	3,486	0	3,486	0	0	0	0	0	0
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	SO	0	0	0	0	0	0	0	0	0
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	UT	6,280	0	0	0	0	6,280	0	0	0
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WA	621	0	0	621	0	0	0	0	0
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WYP	1,540	0	0	0	1,540	0	0	0	0
9282000 Total					**12,704**	**134**	**3,486**	**621**	**1,540**	**6,280**	**644**	**0**	**0**
9283000	FERC FILING FEE	AGEX	Administrative & General Expense	SG	5,234	80	1,362	413	765	2,303	309	1	0
9283000 Total					**5,234**	**80**	**1,362**	**413**	**765**	**2,303**	**309**	**1**	**0**
9290000	DUPLICATE CHRGS-CR	AGEX	Administrative & General Expense	SO	-8,022	-179	-2,183	-618	-1,091	-3,490	-460	-2	0
9290000 Total					**-8,022**	**-179**	**-2,183**	**-618**	**-1,091**	**-3,490**	**-460**	**-2**	**0**
9299100	DUP CHG CR - PENSION	AGEX	Administrative & General Expense	SO	-7,400	-165	-2,014	-570	-1,006	-3,219	-425	-2	0
9299100 Total					**-7,400**	**-165**	**-2,014**	**-570**	**-1,006**	**-3,219**	**-425**	**-2**	**0**
9299200	DUP CHG CR - POST-RT	AGEX	Administrative & General Expense	SO	-2,070	-46	-563	-159	-281	-900	-119	0	0
9299200 Total					**-2,070**	**-46**	**-563**	**-159**	**-281**	**-900**	**-119**	**0**	**0**
9299300	DUP CHRG CR - SERP	AGEX	Administrative & General Expense	SO	-25	-1	-7	-2	-3	-11	-1	0	0
9299300 Total					**-25**	**-1**	**-7**	**-2**	**-3**	**-11**	**-1**	**0**	**0**
9299400	DUP CHG CR - M/D/V/L	AGEX	Administrative & General Expense	SO	-61,452	-1,371	-16,724	-4,731	-8,355	-26,731	-3,527	-13	0

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Operations & Maintenance Expense
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9299400 Total					**-61,452**	**-1,371**	**-16,724**	**-4,731**	**-8,355**	**-26,731**	**-3,527**	**-13**	**0**
9299500	DUP CHRG CR - 401(K)	AGEX	Administrative & General Expense	SO	-37,760	-843	-10,276	-2,907	-5,134	-16,425	-2,167	-8	0
9299500 Total					**-37,760**	**-843**	**-10,276**	**-2,907**	**-5,134**	**-16,425**	**-2,167**	**-8**	**0**
9299600	DUP CHG CR - POST-EM	AGEX	Administrative & General Expense	SO	-6,681	-149	-1,818	-514	-908	-2,906	-383	-1	0
9299600 Total					**-6,681**	**-149**	**-1,818**	**-514**	**-908**	**-2,906**	**-383**	**-1**	**0**
9299700	DUP CHG CR - OTH BEN	AGEX	Administrative & General Expense	SO	-6,718	-150	-1,828	-517	-913	-2,922	-386	-1	0
9299700 Total					**-6,718**	**-150**	**-1,828**	**-517**	**-913**	**-2,922**	**-386**	**-1**	**0**
9301000	GEN ADVERTISNG EXP	AGEX	Administrative & General Expense	SO	43	1	12	3	6	19	2	0	0
9301000 Total					**43**	**1**	**12**	**3**	**6**	**19**	**2**	**0**	**0**
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	CA	1	1	0	0	0	0	0	0	0
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	OR	33	0	33	0	0	0	0	0	0
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	SO	2,118	47	576	163	288	921	122	0	0
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	WA	7	0	0	7	0	0	0	0	0
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	WYP	1	0	0	0	1	0	0	0	0
9302000 Total					**2,160**	**48**	**610**	**170**	**289**	**921**	**122**	**0**	**0**
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	CA	67	67	0	0	0	0	0	0	0
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	IDU	1	0	0	0	0	0	1	0	0
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	OR	259	0	259	0	0	0	0	0	0
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	SO	2,138	48	582	165	291	930	123	0	0
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	UT	10	0	0	0	0	10	0	0	0
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WA	41	0	0	41	0	0	0	0	0
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WYP	42	0	0	0	42	0	0	0	0
9310000 Total					**2,559**	**115**	**841**	**206**	**333**	**940**	**124**	**0**	**0**
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	CA	93	93	0	0	0	0	0	0	0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	CN	59	1	18	4	4	28	2	0	0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	IDU	15	0	0	0	0	0	15	0	0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	OR	167	0	167	0	0	0	0	0	0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	SO	23,206	518	6,316	1,786	3,155	10,094	1,332	5	0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	UT	101	0	0	0	0	101	0	0	0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WA	46	0	0	46	0	0	0	0	0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYP	41	0	0	0	41	0	0	0	0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYU	7	0	0	0	7	0	0	0	0
9350000 Total					**23,737**	**612**	**6,501**	**1,837**	**3,208**	**10,223**	**1,349**	**5**	**0**
9359500	MAINT GEN PLT-ENV AM	AGEX	Administrative & General Expense	SO	7	0	2	1	1	3	0	0	0
9359500 Total					**7**	**0**	**2**	**1**	**1**	**3**	**0**	**0**	**0**
Grand Total					**2,905,517**	**59,212**	**763,943**	**216,121**	**416,243**	**1,258,298**	**176,726**	**759**	**14,215**

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Depreciation Expense

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(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3102000	LAND RIGHTS	SG	909	14	237	72	133	400	54	0	0
4030000	DEPN EXPENSE-ELECT	3110000	STRUCTURES AND IMPROVEMENTS	SG	30,219	464	7,864	2,385	4,420	13,295	1,782	9	0
4030000	DEPN EXPENSE-ELECT	3120000	BOILER PLANT EQUIPMENT	SG	165,812	2,548	43,149	13,086	24,251	72,953	9,779	47	0
4030000	DEPN EXPENSE-ELECT	3140000	TURBOGENERATOR UNITS	SG	34,575	531	8,997	2,729	5,057	15,212	2,039	10	0
4030000	DEPN EXPENSE-ELECT	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	14,892	229	3,875	1,175	2,178	6,552	878	4	0
4030000	DEPN EXPENSE-ELECT	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	1	0	0	0	0	1	0	0	0
4030000	DEPN EXPENSE-ELECT	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	1,386	21	361	109	203	610	82	0	0
4030000	DEPN EXPENSE-ELECT	3302000	LAND RIGHTS	SG-P	102	2	26	8	15	45	6	0	0
4030000	DEPN EXPENSE-ELECT	3302000	LAND RIGHTS	SG-U	10	0	3	1	1	4	1	0	0
4030000	DEPN EXPENSE-ELECT	3303000	WATER RIGHTS	SG-P	0	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	0
4030000	DEPN EXPENSE-ELECT	3304000	FLOOD RIGHTS	SG-P	13	0	3	1	2	6	1	0	0
4030000	DEPN EXPENSE-ELECT	3304000	FLOOD RIGHTS	SG-U	3	0	1	0	0	1	0	0	0
4030000	DEPN EXPENSE-ELECT	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	2	0	0	0	0	1	0	0	0
4030000	DEPN EXPENSE-ELECT	3310000	STRUCTURES AND IMPROVE	SG-P	1	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3310000	STRUCTURES AND IMPROVE	SG-U	259	4	67	20	38	114	15	0	0
4030000	DEPN EXPENSE-ELECT	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	2,077	32	541	164	304	914	123	1	0
4030000	DEPN EXPENSE-ELECT	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	241	4	63	19	35	106	14	0	0
4030000	DEPN EXPENSE-ELECT	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	5,806	89	1,511	458	849	2,555	342	2	0
4030000	DEPN EXPENSE-ELECT	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	12	0	3	1	2	5	1	0	0
4030000	DEPN EXPENSE-ELECT	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	556	9	145	44	81	244	33	0	0
4030000	DEPN EXPENSE-ELECT	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	98	2	26	8	14	43	6	0	0
4030000	DEPN EXPENSE-ELECT	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	87	1	23	7	13	38	5	0	0
4030000	DEPN EXPENSE-ELECT	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	890	14	232	70	130	391	52	0	0
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	13,146	202	3,421	1,037	1,923	5,784	775	4	0
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	3,230	50	841	255	472	1,421	190	1	0
4030000	DEPN EXPENSE-ELECT	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	2,728	42	710	215	399	1,200	161	1	0
4030000	DEPN EXPENSE-ELECT	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	13	0	3	1	2	6	1	0	0
4030000	DEPN EXPENSE-ELECT	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	4	0	1	0	1	2	0	0	0
4030000	DEPN EXPENSE-ELECT	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	3	0	1	0	0	1	0	0	0
4030000	DEPN EXPENSE-ELECT	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	2,535	39	660	200	371	1,116	150	1	0
4030000	DEPN EXPENSE-ELECT	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	2,055	32	535	162	301	904	121	1	0
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	2,670	41	695	211	390	1,175	157	1	0
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	652	10	170	51	95	287	38	0	0
4030000	DEPN EXPENSE-ELECT	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	-107	-2	-28	-8	-16	-47	-6	0	0
4030000	DEPN EXPENSE-ELECT	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	2	0	1	0	0	1	0	0	0
4030000	DEPN EXPENSE-ELECT	3350000	MISC POWER PLANT EQUIP	SG-U	5	0	1	0	1	2	0	0	0
4030000	DEPN EXPENSE-ELECT	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	50	1	13	4	7	22	3	0	0

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Depreciation Expense
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(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	765	12	199	60	112	336	45	0	0
4030000	DEPN EXPENSE-ELECT	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	76	1	20	6	11	33	4	0	0
4030000	DEPN EXPENSE-ELECT	3410000	STRUCTURES & IMPROVEMENTS	SG	6,634	102	1,726	524	970	2,919	391	2	0
4030000	DEPN EXPENSE-ELECT	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	495	8	129	39	72	218	29	0	0
4030000	DEPN EXPENSE-ELECT	3430000	PRIME MOVERS	SG	95,083	1,461	24,743	7,504	13,906	41,834	5,607	27	0
4030000	DEPN EXPENSE-ELECT	3440000	GENERATORS	SG	14,613	225	3,803	1,153	2,137	6,429	862	4	0
4030000	DEPN EXPENSE-ELECT	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	9,557	147	2,487	754	1,398	4,205	564	3	0
4030000	DEPN EXPENSE-ELECT	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	447	7	116	35	65	197	26	0	0
4030000	DEPN EXPENSE-ELECT	3502000	LAND RIGHTS	SG	2,675	41	696	211	391	1,177	158	1	0
4030000	DEPN EXPENSE-ELECT	3520000	STRUCTURES & IMPROVEMENTS	SG	3,872	59	1,008	306	566	1,703	228	1	0
4030000	DEPN EXPENSE-ELECT	3530000	STATION EQUIPMENT	SG	34,644	532	9,015	2,734	5,067	15,242	2,043	10	0
4030000	DEPN EXPENSE-ELECT	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	2,833	44	737	224	414	1,247	167	1	0
4030000	DEPN EXPENSE-ELECT	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	392	6	102	31	57	173	23	0	0
4030000	DEPN EXPENSE-ELECT	3540000	TOWERS AND FIXTURES	SG	19,921	306	5,184	1,572	2,914	8,765	1,175	6	0
4030000	DEPN EXPENSE-ELECT	3550000	POLES AND FIXTURES	SG	20,882	321	5,434	1,648	3,054	9,187	1,231	6	0
4030000	DEPN EXPENSE-ELECT	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	23,526	362	6,122	1,857	3,441	10,351	1,387	7	0
4030000	DEPN EXPENSE-ELECT	3570000	UNDERGROUND CONDUIT	SG	57	1	15	4	8	25	3	0	0
4030000	DEPN EXPENSE-ELECT	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	133	2	35	11	20	59	8	0	0
4030000	DEPN EXPENSE-ELECT	3590000	ROADS AND TRAILS	SG	158	2	41	12	23	69	9	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	CA	25	25	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	IDU	27	0	0	0	0	0	27	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	OR	62	0	62	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	UT	185	0	0	0	0	185	0	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WA	8	0	0	8	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WYP	43	0	0	0	43	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WYU	80	0	0	0	80	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	CA	106	106	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	IDU	50	0	0	0	0	0	50	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	OR	572	0	572	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	UT	956	0	0	0	0	956	0	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WA	88	0	0	88	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WYP	224	0	0	0	224	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WYU	89	0	0	0	89	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	CA	701	701	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	IDU	691	0	0	0	0	0	691	0	0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	OR	4,892	0	4,892	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	UT	11,102	0	0	0	0	11,102	0	0	0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WA	1,546	0	0	1,546	0	0	0	0	0

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(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WYP	2,327	0	0	0	2,327	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WYU	364	0	0	0	364	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	29	29	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	11	0	0	0	0	0	11	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	78	0	78	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	165	0	0	0	0	165	0	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	27	0	0	27	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	40	0	0	0	40	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	5	0	0	0	5	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	CA	2,617	2,617	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	IDU	3,272	0	0	0	0	0	3,272	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	OR	12,836	0	12,836	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	UT	14,114	0	0	0	0	14,114	0	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WA	3,979	0	0	3,979	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WYP	5,326	0	0	0	5,326	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WYU	1,122	0	0	0	1,122	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	1,118	1,118	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	975	0	0	0	0	0	975	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	7,072	0	7,072	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	6,703	0	0	0	0	6,703	0	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	1,850	0	0	1,850	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	2,441	0	0	0	2,441	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	341	0	0	0	341	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	CA	540	540	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	IDU	240	0	0	0	0	0	240	0	0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	OR	1,906	0	1,906	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	UT	5,214	0	0	0	0	5,214	0	0	0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WA	532	0	0	532	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WYP	810	0	0	0	810	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WYU	167	0	0	0	167	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	493	493	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	656	0	0	0	0	0	656	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	3,968	0	3,968	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	14,029	0	0	0	0	14,029	0	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	740	0	0	740	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	1,538	0	0	0	1,538	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	618	0	0	0	618	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	CA	1,382	1,382	0	0	0	0	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	IDU	1,945	0	0	0	0	0	1,945	0	0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	OR	11,127	0	11,127	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	UT	12,773	0	0	0	0	12,773	0	0	0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WA	3,027	0	0	3,027	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WYP	3,484	0	0	0	3,484	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WYU	494	0	0	0	494	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	CA	184	184	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	IDU	199	0	0	0	0	0	199	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	OR	2,193	0	2,193	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	UT	2,044	0	0	0	0	2,044	0	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WA	537	0	0	537	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WYP	359	0	0	0	359	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WYU	69	0	0	0	69	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	CA	301	301	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	IDU	768	0	0	0	0	0	768	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	OR	4,583	0	4,583	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	UT	5,321	0	0	0	0	5,321	0	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WA	1,105	0	0	1,105	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WYP	936	0	0	0	936	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WYU	321	0	0	0	321	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	CA	317	317	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	IDU	636	0	0	0	0	0	636	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	OR	3,047	0	3,047	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	UT	3,527	0	0	0	0	3,527	0	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WA	516	0	0	516	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WYP	542	0	0	0	542	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WYU	97	0	0	0	97	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	CA	13	13	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	10	0	0	0	0	0	10	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	OR	126	0	126	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	UT	270	0	0	0	0	270	0	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WA	18	0	0	18	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	50	0	0	0	50	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	9	0	0	0	9	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	23	23	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	35	0	0	0	0	0	35	0	0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	699	0	699	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	1,041	0	0	0	0	1,041	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	125	0	0	125	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	246	0	0	0	246	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	66	0	0	0	66	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	IDU	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	SG	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	UT	2	0	0	0	0	2	0	0	0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	WYP	1	0	0	0	1	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	WYU	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	CA	56	56	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	CN	125	3	39	9	9	60	5	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	IDU	185	0	0	0	0	0	185	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	OR	626	0	626	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SE	18	0	4	1	3	8	1	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SG	131	2	34	10	19	58	8	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SO	1,579	35	430	122	215	687	91	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	UT	678	0	0	0	0	678	0	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WA	290	0	0	290	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WYP	178	0	0	0	178	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WYU	90	0	0	0	90	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	CA	5	5	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	CN	53	1	17	4	4	25	2	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	IDU	4	0	0	0	0	0	4	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	OR	75	0	75	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SE	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SG	70	1	18	6	10	31	4	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SO	597	13	162	46	81	259	34	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	UT	34	0	0	0	0	34	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WA	3	0	0	3	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WYP	26	0	0	0	26	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WYU	1	0	0	0	1	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	11	11	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	692	17	216	48	51	331	29	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	59	0	0	0	0	0	59	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	143	0	143	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	1	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	292	4	76	23	43	129	17	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	8,953	200	2,437	689	1,217	3,894	514	2	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	113	0	0	0	0	113	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	53	0	0	53	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	350	0	0	0	350	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	7	0	0	0	7	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	CN	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	IDU	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	OR	1	0	1	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	SG	8	0	2	1	1	4	0	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	SO	22	0	6	2	3	9	1	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	UT	1	0	0	0	0	1	0	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	WYP	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	WYU	1	0	0	0	1	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	CA	7	7	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	IDU	20	0	0	0	0	0	20	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	OR	107	0	107	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	SG	232	4	60	18	34	102	14	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	SO	10	0	3	1	1	4	1	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	UT	129	0	0	0	0	129	0	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WA	28	0	0	28	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WYP	44	0	0	0	44	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WYU	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	30	30	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	84	0	0	0	0	0	84	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	435	0	435	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	3	0	1	0	1	1	0	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	995	15	259	79	146	438	59	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	89	2	24	7	12	39	5	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	576	0	0	0	0	576	0	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	113	0	0	113	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	156	0	0	0	156	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	17	0	0	0	17	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	CA	15	15	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	IDU	65	0	0	0	0	0	65	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	OR	390	0	390	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SE	54	1	14	4	9	23	4	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SG	322	5	84	25	47	142	19	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SO	238	5	65	18	32	103	14	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	UT	388	0	0	0	0	388	0	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WA	64	0	0	64	0	0	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WYP	123	0	0	0	123	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WYU	6	0	0	0	6	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	CA	248	248	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	CN	166	4	52	11	12	79	7	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	IDU	470	0	0	0	0	0	470	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	OR	3,017	0	3,017	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SE	11	0	3	1	2	5	1	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SG	7,604	117	1,979	600	1,112	3,346	448	2	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SO	3,925	88	1,068	302	534	1,707	225	1	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	UT	2,634	0	0	0	0	2,634	0	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WA	545	0	0	545	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WYP	1,076	0	0	0	1,076	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WYU	255	0	0	0	255	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	CA	28	28	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	IDU	30	0	0	0	0	0	30	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	OR	231	0	231	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SE	7	0	2	1	1	3	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SG	367	6	96	29	54	162	22	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SO	45	1	12	3	6	20	3	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	UT	181	0	0	0	0	181	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WA	49	0	0	49	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WYP	68	0	0	0	68	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WYU	9	0	0	0	9	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	CA	3	3	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	CN	4	0	1	0	0	2	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	IDU	4	0	0	0	0	0	4	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	OR	54	0	54	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SE	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SG	132	2	34	10	19	58	8	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SO	110	2	30	8	15	48	6	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	UT	65	0	0	0	0	65	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WA	9	0	0	9	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WYP	8	0	0	0	8	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WYU	2	0	0	0	2	0	0	0	0
4030000 Total					**747,608**	**16,800**	**201,228**	**58,504**	**104,619**	**323,560**	**42,743**	**154**	**0**
4032000	DEPR - STEAM	565131	DEPR - PROD STEAM NOT CLASSIFIED	SG	-2,125	-33	-553	-168	-311	-935	-125	-1	0
4032000 Total					**-2,125**	**-33**	**-553**	**-168**	**-311**	**-935**	**-125**	**-1**	**0**
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-P	2,190	34	570	173	320	964	129	1	0

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Depreciation Expense
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-U	-245	-4	-64	-19	-36	-108	-14	0	0
4033000 Total					**1,945**	**30**	**506**	**153**	**284**	**856**	**115**	**1**	**0**
4034000	DEPR - OTHER	565134	DEPR - PROD OTHER NOT CLASSIFIED	SG	830	13	216	66	121	365	49	0	0
4034000 Total					**830**	**13**	**216**	**66**	**121**	**365**	**49**	**0**	**0**
4035000	DEPR-TRANSMISSION	565141	DEPR - TRANS ASSETS NOT CLASSIFIED	SG	1,800	28	468	142	263	792	106	1	0
4035000 Total					**1,800**	**28**	**468**	**142**	**263**	**792**	**106**	**1**	**0**
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	CA	86	86	0	0	0	0	0	0	0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	IDU	-2,449	0	0	0	0	0	-2,449	0	0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	OR	448	0	448	0	0	0	0	0	0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	UT	-22,476	0	0	0	0	-22,476	0	0	0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WA	214	0	0	214	0	0	0	0	0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WYP	-1,892	0	0	0	-1,892	0	0	0	0
4036000 Total					**-26,069**	**86**	**448**	**214**	**-1,892**	**-22,476**	**-2,449**	**0**	**0**
4037000	DEPR - GENERAL	565201	DEPR - GEN ASSETS NOT CLASSIFIED	SG	795	12	207	63	116	350	47	0	0
4037000 Total					**795**	**12**	**207**	**63**	**116**	**350**	**47**	**0**	**0**
4039999	DEPR EXP-ELEC, OTH	565970	DEPRECIATION-JOINT OWNER BILLED-CREDIT	SG	-240	-4	-62	-19	-35	-105	-14	0	0
4039999 Total					**-240**	**-4**	**-62**	**-19**	**-35**	**-105**	**-14**	**0**	**0**
Grand Total					**724,544**	**16,933**	**202,457**	**58,955**	**103,166**	**302,406**	**40,472**	**155**	**0**

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Amortization Expense
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	IDU	20	0	0	0	0	0	20	0	0
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG	584	9	152	46	85	257	34	0	0
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-P	10,901	168	2,837	860	1,594	4,796	643	3	0
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-U	331	5	86	26	48	146	20	0	0
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	UT	-3,602	0	0	0	0	-3,602	0	0	0
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	OR	9	0	9	0	0	0	0	0	0
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	SG	1,400	22	364	111	205	616	83	0	0
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	UT	21	0	0	0	0	21	0	0	0
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	WYP	55	0	0	0	55	0	0	0	0
4040000	AMOR LTD TRM PLNT	3031050	RWT - RCMS WORK TRACKING	SO	14	0	4	1	2	6	1	0	0
4040000	AMOR LTD TRM PLNT	3031680	DISTRIBUTION AUTOMATION PILOT	SO	236	5	64	18	32	103	14	0	0
4040000	AMOR LTD TRM PLNT	3031830	CUSTOMER SERVICE SYSTEM	CN	3,076	74	960	213	228	1,471	129	0	0
4040000	AMOR LTD TRM PLNT	3032040	SAP	SO	2,473	55	673	190	336	1,076	142	1	0
4040000	AMOR LTD TRM PLNT	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	23	1	6	2	3	10	1	0	0
4040000	AMOR LTD TRM PLNT	3032360	2002 GRID NET POWER COST MODELING	SO	5	0	1	0	1	2	0	0	0
4040000	AMOR LTD TRM PLNT	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	241	5	66	19	33	105	14	0	0
4040000	AMOR LTD TRM PLNT	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	13	0	4	1	2	6	1	0	0
4040000	AMOR LTD TRM PLNT	3032600	SINGLE PERSON SCHEDULING	SO	438	10	119	34	60	191	25	0	0
4040000	AMOR LTD TRM PLNT	3032640	TIBCO SOFTWARE	SO	397	9	108	31	54	173	23	0	0
4040000	AMOR LTD TRM PLNT	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	4	0	1	0	1	2	0	0	0
4040000	AMOR LTD TRM PLNT	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	8	0	2	1	1	3	0	0	0
4040000	AMOR LTD TRM PLNT	3032740	GADSBY INTANGIBLE ASSETS	SG	3	0	1	0	0	1	0	0	0
4040000	AMOR LTD TRM PLNT	3032760	SWIFT 2 IMPROVEMENTS	SG	432	7	112	34	63	190	25	0	0
4040000	AMOR LTD TRM PLNT	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	24	0	6	2	4	11	1	0	0
4040000	AMOR LTD TRM PLNT	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	5	0	1	0	1	2	0	0	0
4040000	AMOR LTD TRM PLNT	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG-U	1	0	0	0	0	0	0	0	0
4040000	AMOR LTD TRM PLNT	3032830	VCPRO - XEROX CUST STMT FRMTR ENHANCE -	SO	107	2	29	8	15	47	6	0	0
4040000	AMOR LTD TRM PLNT	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	360	6	94	28	53	158	21	0	0
4040000	AMOR LTD TRM PLNT	3032990	P8DM - FILENET P8 DOCUMENT MANAGEMENT (E	SO	220	5	60	17	30	96	13	0	0
4040000	AMOR LTD TRM PLNT	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	2,739	42	713	216	401	1,205	162	1	0
4040000	AMOR LTD TRM PLNT	3033170	GTX VERSION 7 SOFTWARE	CN	624	15	195	43	46	299	26	0	0
4040000	AMOR LTD TRM PLNT	3033210	ArcFM Software	SO	801	18	218	62	109	348	46	0	0
4040000	AMOR LTD TRM PLNT	3033220	MONARCH EMS/SCADA	SO	2,920	65	795	225	397	1,270	168	1	0
4040000	AMOR LTD TRM PLNT	3033230	VREALIZE VMWARE - SHARED	SO	211	5	57	16	29	92	12	0	0
4040000	AMOR LTD TRM PLNT	3033240	IEE - Itron Enterprise Addition	CN	738	18	230	51	55	353	31	0	0
4040000	AMOR LTD TRM PLNT	3033250	AMI Metering Software	CN	4,472	107	1,396	310	332	2,139	188	0	0
4040000	AMOR LTD TRM PLNT	3033260	Big Data & Analytics	SO	84	2	23	6	11	36	5	0	0
4040000	AMOR LTD TRM PLNT	3033310	C&T - ENERGY TRADING SYSTEM	SO	1,134	25	309	87	154	493	65	0	0
4040000	AMOR LTD TRM PLNT	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SO	1,244	28	339	96	169	541	71	0	0

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Amortization Expense
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4040000	AMOR LTD TRM PLNT	3033370	DISTRIBUTION INTANGIBLES	WYP	4	0	0	0	4	0	0	0	0
4040000	AMOR LTD TRM PLNT	3033390	RMT TRADE SYSTEM	SO	188	4	51	14	26	82	11	0	0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	CA	2	2	0	0	0	0	0	0	0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	CN	2	0	1	0	0	1	0	0	0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	IDU	3	0	0	0	0	0	3	0	0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	OR	1	0	1	0	0	0	0	0	0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SE	1	0	0	0	0	1	0	0	0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SG	8,950	138	2,329	706	1,309	3,938	528	3	0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SO	241	5	66	19	33	105	14	0	0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	UT	5	0	0	0	0	5	0	0	0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WA	3	0	0	3	0	0	0	0	0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WYP	49	0	0	0	49	0	0	0	0
4040000	AMOR LTD TRM PLNT	3035320	HYDRO PLANT INTANGIBLES	SG	156	2	41	12	23	68	9	0	0
4040000	AMOR LTD TRM PLNT	3035320	HYDRO PLANT INTANGIBLES	SG-P	15	0	4	1	2	6	1	0	0
4040000	AMOR LTD TRM PLNT	3035322	ACD–Call Center Automated Call Distribut	CN	815	20	254	56	60	390	34	0	0
4040000	AMOR LTD TRM PLNT	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	311	5	81	25	46	137	18	0	0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	67	67	0	0	0	0	0	0	0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	308	0	308	0	0	0	0	0	0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	290	6	79	22	39	126	17	0	0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	1	0	0	0	0	1	0	0	0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	82	0	0	82	0	0	0	0	0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	119	0	0	0	119	0	0	0	0
4040000 Total					**44,380**	**957**	**13,250**	**3,698**	**6,318**	**17,522**	**2,626**	**10**	**0**
4049000	AMR LTD TRM PLNT-OTH	566201	Amort Exp - Hydro - UT Klamath Adj	OTHER	4,252	0	0	0	0	0	0	0	4,252
4049000	AMR LTD TRM PLNT-OTH	566970	AMORTIZATION JO BILL CREDIT	SG	-237	-4	-62	-19	-35	-104	-14	0	0
4049000 Total					**4,015**	**-4**	**-62**	**-19**	**-35**	**-104**	**-14**	**0**	**4,252**
4061000	EL PLNT ACQ ADJ-CM	566920	AMORT ELEC PLANT ACQ ADJ	SG	4,782	73	1,244	377	699	2,104	282	1	0
4061000	EL PLNT ACQ ADJ-CM	566920	AMORT ELEC PLANT ACQ ADJ	UT	302	0	0	0	0	302	0	0	0
4061000 Total					**5,083**	**73**	**1,244**	**377**	**699**	**2,405**	**282**	**1**	**0**
4073000	REGULATORY DEBITS	586902	Preferred Stock Repurchase Loss Amort	OTHER	124	0	0	0	0	0	0	0	124
4073000 Total					**124**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**124**
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	IDU	5,656	0	0	0	0	0	5,656	0	0
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	OR	43,788	0	43,788	0	0	0	0	0	0
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	WA	12,601	0	0	12,601	0	0	0	0	0
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	IDU	405	0	0	0	0	0	405	0	0
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	OR	980	0	980	0	0	0	0	0	0
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	WA	665	0	0	665	0	0	0	0	0
4074100	Reg Credits-BPA Exch	301301	BPA Reg Bill Bal Acct - Industrial	IDU	43	0	0	0	0	0	43	0	0
4074100	Reg Credits-BPA Exch	301301	BPA Reg Bill Bal Acct - Industrial	OR	2	0	2	0	0	0	0	0	0

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Amortization Expense
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4074100	Reg Credits-BPA Exch	301301	BPA Reg Bill Bal Acct - Industrial	WA	19	0	0	19	0	0	0	0	0
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	IDU	1,971	0	0	0	0	0	1,971	0	0
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	OR	904	0	904	0	0	0	0	0	0
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	WA	716	0	0	716	0	0	0	0	0
4074100	Reg Credits-BPA Exch	301601	BPA Reg Bill Bal Acct - St/Hwy Lighting	OR	0	0	0	0	0	0	0	0	0
4074100 Total					**67,750**	**0**	**45,674**	**14,000**	**0**	**0**	**8,076**	**0**	**0**
4074200	Reg Credits-BPA Exch	505201	Regional Bill Intchg Rec/Del-OR (PP)	OR	-45,675	0	-45,675	0	0	0	0	0	0
4074200	Reg Credits-BPA Exch	505202	Regional Bill Intchg Rec/Del-WA (PP)	WA	-13,999	0	0	-13,999	0	0	0	0	0
4074200	Reg Credits-BPA Exch	505204	Regional Bill Intchg Rec/Del-ID (RMP)	IDU	-8,076	0	0	0	0	0	-8,076	0	0
4074200 Total					**-67,750**	**0**	**-45,675**	**-13,999**	**0**	**0**	**-8,076**	**0**	**0**
Grand Total					**53,602**	**1,027**	**14,431**	**4,058**	**6,982**	**19,823**	**2,894**	**11**	**4,376**

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Taxes Other Than Income
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4081000	TAX OTH INC-U OP I	583750	SALES AND USE TAX	SO	208	5	57	16	28	91	12	0	0
4081000	TAX OTH INC-U OP I	584960	Taxes Other Non-Income - Credit	SO	-446	-10	-121	-34	-61	-194	-26	0	0
4081000 Total					**-238**	**-5**	**-65**	**-18**	**-32**	**-103**	**-14**	**0**	**0**
4081500	PROPERTY TAXES	579000	PROPERTY TAX	GPS	149,367	3,333	40,651	11,499	20,309	64,973	8,572	30	0
4081500 Total					**149,367**	**3,333**	**40,651**	**11,499**	**20,309**	**64,973**	**8,572**	**30**	**0**
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	CA	1,228	1,228	0	0	0	0	0	0	0
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	GPS	3	0	1	0	0	1	0	0	0
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	OR	30,080	0	30,080	0	0	0	0	0	0
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	WYP	1,883	0	0	0	1,883	0	0	0	0
4081800 Total					**33,195**	**1,228**	**30,081**	**0**	**1,884**	**1**	**0**	**0**	**0**
4081990	MISC TAXES - OTHER	583260	PUBLIC UTILITY TAX	SO	12,550	280	3,416	966	1,706	5,459	720	3	0
4081990	MISC TAXES - OTHER	583261	OREGON ENERGY RESOURCE SUPPLIER TAX	OR	1,724	0	1,724	0	0	0	0	0	0
4081990	MISC TAXES - OTHER	583263	MONTANA ENERGY TAX	SE	198	3	50	15	32	86	13	0	0
4081990	MISC TAXES - OTHER	583265	WASHINGTON GROSS REVENUE TAX - SERVICES	WA	26	0	0	26	0	0	0	0	0
4081990	MISC TAXES - OTHER	583266	IDAHO KILOWATT HOUR TAX	SE	58	1	14	4	9	25	4	0	0
4081990	MISC TAXES - OTHER	583267	WYOMING ANNUAL CORPORATION FEE (TAX)	WYP	71	0	0	0	71	0	0	0	0
4081990	MISC TAXES - OTHER	583269	MONTANA WHOLESALE ENERGY TAX	SE	141	2	35	11	23	61	9	0	0
4081990	MISC TAXES - OTHER	583273	Wyoming Wind Generation Tax	SG	1,956	30	509	154	286	860	115	1	0
4081990	MISC TAXES - OTHER	583274	Nevada Commerce Tax	SO	48	1	13	4	7	21	3	0	0
4081990	MISC TAXES - OTHER	584100	GOVERNMENT ROYALTIES	SE	446	6	112	34	71	194	29	0	0
4081990 Total					**17,217**	**323**	**5,873**	**1,213**	**2,205**	**6,706**	**894**	**3**	**0**
Grand Total					**199,542**	**4,880**	**76,540**	**12,694**	**24,365**	**71,577**	**9,452**	**34**	**0**

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Interest Expense & Production Tax Credits
Twelve Months Ended - June 2019
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	-45,353	-697	-11,802	-3,579	-6,633	-19,954	-2,675	-13	0
4091000	INC TX UTIL OP INC	310312	Mining Rescue Training Credit ~ Energy W	SE	0	0	0	0	0	0	0	0	0
4091000	INC TX UTIL OP INC	310313	Mining Rescue Training Credit ~ PMI	SE	0	0	0	0	0	0	0	0	0
4091000	INC TX UTIL OP INC	310314	HR Hiring Retention Tax Credit	SO	0	0	0	0	0	0	0	0	0
4091000	INC TX UTIL OP INC	310315	Investment Tax Credit - Solar Arrays	SG	0	0	0	0	0	0	0	0	0
4091000	INC TX UTIL OP INC	310318	Research and Experimentation Credits	SO	-33	-1	-9	-3	-4	-14	-2	0	0
4091000	INC TX UTIL OP INC	600600	Fuel Tax Credit	SE	-19	0	-5	-1	-3	-8	-1	0	0
4091000	INC TX UTIL OP INC	900900	Foreign Tax Credit	SO	-9	0	-2	-1	-1	-4	-1	0	0
4091000 Total					**-45,413**	**-698**	**-11,818**	**-3,584**	**-6,642**	**-19,980**	**-2,678**	**-13**	**0**
4091100	STATE INC TAX-ELEC	311311	Utah Renewable Energy Production Tax Cre	SG	0	0	0	0	0	0	0	0	0
4091100 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4191000	AFUDC - OTHER	0	AFUDC - EQUITY	SNP	-49,461	-1,034	-13,004	-3,660	-6,712	-22,189	-2,843	-10	-9
4191000 Total					**-49,461**	**-1,034**	**-13,004**	**-3,660**	**-6,712**	**-22,189**	**-2,843**	**-10**	**-9**
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	OR	715	0	715	0	0	0	0	0	0
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	SG	-137	-2	-36	-11	-20	-60	-8	0	0
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	SO	-3,965	-88	-1,079	-305	-539	-1,725	-228	-1	0
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	UT	-16	0	0	0	0	-16	0	0	0
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	WA	-1	0	0	-1	0	0	0	0	0
4211000 Total					**-3,404**	**-91**	**-400**	**-317**	**-559**	**-1,801**	**-236**	**-1**	**0**
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	CA	15	15	0	0	0	0	0	0	0
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	OR	17	0	17	0	0	0	0	0	0
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	SG	27	0	7	2	4	12	2	0	0
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	SO	14	0	4	1	2	6	1	0	0
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	WYP	0	0	0	0	0	0	0	0	0
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	WYU	5	0	0	0	5	0	0	0	0
4212000 Total					**78**	**16**	**28**	**3**	**11**	**18**	**2**	**0**	**0**
4270000	INT ON LNG-TRM DBT	585001	INTEREST EXPENSE - LONG-TERM DEBT - FMBS	SNP	323,869	6,773	85,152	23,964	43,947	145,290	18,615	67	60
4270000	INT ON LNG-TRM DBT	585002	INTEREST EXPENSE - LONG-TERM DEBT - MTNS	SNP	31,567	660	8,300	2,336	4,283	14,161	1,814	7	6
4270000	INT ON LNG-TRM DBT	585004	INTEREST EXPENSE - LT DEBT - PCRBS VARIA	SNP	4,113	86	1,081	304	558	1,845	236	1	1
4270000	INT ON LNG-TRM DBT	585005	INTEREST EXPENSE - LT DEBT - PCRB FEES &	SNP	1,461	31	384	108	198	655	84	0	0
4270000 Total					**361,010**	**7,550**	**94,917**	**26,712**	**48,987**	**161,952**	**20,749**	**75**	**67**
4280000	AMT DBT DISC & EXP	586160	AMORTIZATION - DEBT DISCOUNT	SNP	931	19	245	69	126	418	54	0	0
4280000	AMT DBT DISC & EXP	586170	AMORTIZATION - DEBT ISSUANCE EXP	SNP	2,944	62	774	218	400	1,321	169	1	1
4280000 Total					**3,875**	**81**	**1,019**	**287**	**526**	**1,738**	**223**	**1**	**1**
4281000	AMORTZN OF LOSS	586190	AMORTIZATION - LOSS ON REQACQUIRED DEBT	SNP	585	12	154	43	79	262	34	0	0
4281000 Total					**585**	**12**	**154**	**43**	**79**	**262**	**34**	**0**	**0**
4290000	AMT PREM ON DEBT	586180	AMORTIZATION - DEBT PREMIUM/GAIN	SNP	-11	0	-3	-1	-1	-5	-1	0	0
4290000 Total					**-11**	**0**	**-3**	**-1**	**-1**	**-5**	**-1**	**0**	**0**
4310000	OTHER INTEREST EXP	0	4310000/0	SNP	10,934	229	2,875	809	1,484	4,905	628	2	2
4310000 Total					**10,934**	**229**	**2,875**	**809**	**1,484**	**4,905**	**628**	**2**	**2**
4313000	INT EXP ON REG LIAB	0	INTEREST EXPENSE ON REG LIABILITIES	SNP	11,054	231	2,906	818	1,500	4,959	635	2	2

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Interest Expense & Production Tax Credits

Twelve Months Ended - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4313000 Total					**11,054**	**231**	**2,906**	**818**	**1,500**	**4,959**	**635**	**2**	**2**
4320000	AFUDC - BORROWED	585800	INTEREST CAPITALIZED (SEE OTH INCOME)	SNP	-25,672	-537	-6,750	-1,900	-3,484	-11,517	-1,476	-5	-5
4320000	AFUDC - BORROWED	585860	INTEREST EXPENSE - AFUDC MANUAL ADJ	SNP	205	4	54	15	28	92	12	0	0
4320000 Total					**-25,467**	**-533**	**-6,696**	**-1,884**	**-3,456**	**-11,425**	**-1,464**	**-5**	**-5**
Grand Total					**263,779**	**5,763**	**69,977**	**19,226**	**35,217**	**118,436**	**15,051**	**51**	**58**

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Schedule M
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4098200	105105	30% Capitalized labor costs for PowerTax	SO	0	0	0	0	0	0	0	0	0
4098200	105127	Book Depr Allocated to Medicare and M&E	SCHMDEXP	129	3	35	10	18	56	7	0	0
4098200	110200	Tax Percentage Depletion - Deer Creek	SE	0	0	0	0	0	0	0	0	0
4098200	120101	Other A/R Bad Debt Write-offs	BADDEBT	0	0	0	0	0	0	0	0	0
4098200	130100	Non - Deductible Expenses	SO	1,509	34	411	116	205	656	87	0	0
4098200	130400	PMINondeductible Exp	SE	40	1	10	3	6	17	3	0	0
4098200	130550	MEHC Insurance Services-Premium	SO	0	0	0	0	0	0	0	0	0
4098200	130700	Mining Rescue Training Credit Addback	SE	0	0	0	0	0	0	0	0	0
4098200	130750	Nondeductible Fringe Benefits	SO	527	12	143	41	72	229	30	0	0
4098200	130755	Nondeductible Parking Costs	SO	329	7	90	25	45	143	19	0	0
4098200	130900	Non - Deductible Executive Comp	SO	0	0	0	0	0	0	0	0	0
4098200	505505	Income Tax Interest	SO	-2	0	-1	0	0	-1	0	0	0
4098200	610106	PMIFuel Tax Cr	SE	19	0	5	1	3	8	1	0	0
4098200	610107	PMI Dividend Gross Up for Foreign Tax Cr	SO	9	0	2	1	1	4	1	0	0
4098200	7201051	Contra Medicare Subsidy	SO	0	0	0	0	0	0	0	0	0
4098200	920106	PMI Dividend Received Deduction	SE	0	0	0	0	0	0	0	0	0
4098200	920145	PMI Mining Rescue Training Credit Addbac	SE	0	0	0	0	0	0	0	0	0
4098200 Total				**2,559**	**56**	**694**	**197**	**350**	**1,113**	**147**	**1**	**0**
4098300	105100	Capitalized Labor Costs	SO	1,987	44	541	153	270	864	114	0	0
4098300	105120	Book Depreciation	SCHMDEXP	984,008	19,836	262,984	76,785	138,238	429,222	56,716	226	0
4098300	105121	PMIBook Depreciation	SE	16,621	242	4,172	1,250	2,656	7,206	1,090	5	0
4098300	105123	Sec. 481a Adj - Repair Deduction	SG	0	0	0	0	0	0	0	0	0
4098300	105130	CIAC	CIAC	103,001	3,732	27,559	6,332	10,542	49,577	5,258	0	0
4098300	105137	Auto Depreciation	SO	0	0	0	0	0	0	0	0	0
4098300	105140	Highway relocation	SNPD	2,099	76	562	129	215	1,010	107	0	0
4098300	105142	Avoided Costs	SNP	41,262	863	10,849	3,053	5,599	18,510	2,372	9	8
4098300	105145	Acquisition Adjustment Amort	SG	0	0	0	0	0	0	0	0	0
4098300	105146	Capitalization of Test Energy	SG	0	0	0	0	0	0	0	0	0
4098300	105147	Sec 1031 Like Kind Exchange	SO	0	0	0	0	0	0	0	0	0
4098300	105165	Coal Mine Development	SE	0	0	0	0	0	0	0	0	0
4098300	105170	Coal Mine Receding Face (Extension)	SE	0	0	0	0	0	0	0	0	0
4098300	105180	Steam Rts Blundell Geothml Bk Depr	SG	0	0	0	0	0	0	0	0	0
4098300	105205	Coal Mine Development-30%Amort	SE	0	0	0	0	0	0	0	0	0
4098300	105471	UT Kalamath Relicensing Costs	OTHER	0	0	0	0	0	0	0	0	0
4098300	110100	Book Cost Depletion	SE	0	0	0	0	0	0	0	0	0
4098300	110105	SRC Book Depletion step up basis adj	SG	0	0	0	0	0	0	0	0	0

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Schedule M
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4098300	1101051	SRC Book Cost Depletion	SG	0	0	0	0	0	0	0	0	0
4098300	120105	Willow Wind Account Receivable	WA	0	0	0	0	0	0	0	0	0
4098300	205100	Coal Pile Inventory Adjustment	SE	248	4	62	19	40	108	16	0	0
4098300	205210	ERC (Emission Reduction Credit) Impairme	SE	0	0	0	0	0	0	0	0	0
4098300	205411	PMI Sec 263A Adjustment	SE	0	0	0	0	0	0	0	0	0
4098300	210105	Self Insured Health Benefit	SO	0	0	0	0	0	0	0	0	0
4098300	210120	Prepaid Taxes-UT PUC	UT	0	0	0	0	0	0	0	0	0
4098300	210130	Prepaid Taxes-ID PUC	IDU	0	0	0	0	0	0	0	0	0
4098300	210200	Prepaid Taxes-property taxes	GPS	-591	-13	-161	-46	-80	-257	-34	0	0
4098300	220100	Bad Debts Allowance - Cash Basis	BADDEBT	397	22	142	49	29	134	21	0	0
4098300	320110	Transition Team Costs-UT	UT	0	0	0	0	0	0	0	0	0
4098300	320115	Misc - Reg Assets/Reg Liab-Total	OTHER	0	0	0	0	0	0	0	0	0
4098300	320140	May 2000 Transition Plan Costs-OR	OR	0	0	0	0	0	0	0	0	0
4098300	320210	Research & Exper. Sec. 174 Amort.	SO	0	0	0	0	0	0	0	0	0
4098300	320220	Glenrock Excluding Reclamation-UT rate o	UT	0	0	0	0	0	0	0	0	0
4098300	320230	FAS 87/88 Writeoff-UT rate order	UT	0	0	0	0	0	0	0	0	0
4098300	320270	Reg Asset FAS 158 Pension Liab Adj	SO	36,372	812	9,899	2,800	4,945	15,821	2,087	7	0
4098300	320280	Reg Asset FAS 158 Post Retire Liab	SO	-14,044	-313	-3,822	-1,081	-1,910	-6,109	-806	-3	0
4098300	320281	Reg Asset - Post-Retirement Settlement L	SO	353	8	96	27	48	154	20	0	0
4098300	320282	Reg Asset - Post-Retirement Settlement L	UT	-291	0	0	0	0	-291	0	0	0
4098300	320283	Reg Asset - Post-Retirement Settlement L	WYU	22	0	0	0	22	0	0	0	0
4098300	330100	Amort. Pollution Control Facility	SG	0	0	0	0	0	0	0	0	0
4098300	415110	Def Reg Asset-Transmission Srvc Deposit	SG	0	0	0	0	0	0	0	0	0
4098300	415115	Reg Asset - UT STEP Pilot Programs Balan	OTHER	8,871	0	0	0	0	0	0	0	8,871
4098300	415120	Def Reg Asset-Foote Creek Contract	SG	0	0	0	0	0	0	0	0	0
4098300	415200	Reg Asset - OR Transportation Electrific	OTHER	0	0	0	0	0	0	0	0	0
4098300	415300	Environmental Cleanup Accrual	SO	0	0	0	0	0	0	0	0	0
4098300	415301	Environmental Costs WA	WA	104	0	0	104	0	0	0	0	0
4098300	415406	Reg Asset Utah ECAM	OTHER	0	0	0	0	0	0	0	0	0
4098300	415423	Contra PP&E Deer Creek	SE	0	0	0	0	0	0	0	0	0
4098300	415424	Contra Reg Asset - Deer Creek Abandonmen	SE	15,774	229	3,959	1,186	2,521	6,839	1,034	5	0
4098300	415425	Contra Reg Asset - UMWA Pension	OTHER	454	0	0	0	0	0	0	0	454
4098300	415430	Reg Asset - CA - Transportation Electri	OTHER	445	0	0	0	0	0	0	0	445
4098300	415500	Cholla Plt Transact Costs-APS Amort	SGCT	0	0	0	0	0	0	0	0	0
4098300	415510	WA Disallowed Colstrip #3 Write-off	WA	52	0	0	52	0	0	0	0	0
4098300	415555	WY PCAM Def Net Power Costs	WYP	0	0	0	0	0	0	0	0	0
4098300	415640	IDAI Costs-Direct Access-CA	CA	0	0	0	0	0	0	0	0	0

Schedule M
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4098300	415650	SB 1149-Related Reg Assets-OR	OTHER	0	0	0	0	0	0	0	0	0
4098300	415680	OR Deferred Intevenor Funding Grants	OR	0	0	0	0	0	0	0	0	0
4098300	415700	Reg Liability BPA balancing accounts-OR	OTHER	0	0	0	0	0	0	0	0	0
4098300	415701	CA Deferred Intervenor Funding	CA	0	0	0	0	0	0	0	0	0
4098300	415702	Reg Asset - Lake Side Liq.	WYP	27	0	0	0	27	0	0	0	0
4098300	415703	Goodnoe Hills Liquidation Damages - WY	WYP	21	0	0	0	21	0	0	0	0
4098300	415704	Reg Liability - Tax Revenue Adjustment -	UT	0	0	0	0	0	0	0	0	0
4098300	415705	Reg Liability - Tax Revenue Adjustment -	WYP	0	0	0	0	0	0	0	0	0
4098300	415710	Reg Liability - WA - Accelerated Depreci	WA	12,612	0	0	12,612	0	0	0	0	0
4098300	415801	Contra RTO Grid West N/R Allowance	SG	0	0	0	0	0	0	0	0	0
4098300	415802	Contra RTO Grid West N/R w/o-WA	WA	0	0	0	0	0	0	0	0	0
4098300	415803	WA RTO Grid West N/R w/o	WA	0	0	0	0	0	0	0	0	0
4098300	415804	RTO Grid West Notes Receivable-OR	OR	0	0	0	0	0	0	0	0	0
4098300	415805	RTO Grid West Notes Receivable-WY	WYP	0	0	0	0	0	0	0	0	0
4098300	415806	ID RTO Grid West N/R	IDU	0	0	0	0	0	0	0	0	0
4098300	415822	Reg Asset _ Pension MMT -UT	UT	0	0	0	0	0	0	0	0	0
4098300	415827	Regulatory Asset - Post -Ret MMT -OR	OR	97	0	97	0	0	0	0	0	0
4098300	415828	Regulatory Asset - Post -Ret MMT -WY	WYP	0	0	0	0	0	0	0	0	0
4098300	415829	Reg Asset - Post - Ret MMT -UT	UT	0	0	0	0	0	0	0	0	0
4098300	415830	Regulatory Asset - Post - Ret MMT -ID	IDU	0	0	0	0	0	0	0	0	0
4098300	415831	Regulatory Asset - Post - Ret MMT -CA	CA	9	9	0	0	0	0	0	0	0
4098300	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	0	0	0	0	0	0	0	0	0
4098300	415850	UNRECOVERED PLANT-POWERDALE	SG	0	0	0	0	0	0	0	0	0
4098300	415852	Powerdale Decommissioning Reg Asset - ID	IDU	25	0	0	0	0	0	25	0	0
4098300	415853	Powerdale Decommissioning Reg Asset - OR	OR	0	0	0	0	0	0	0	0	0
4098300	415854	Powerdale Decommissioning Reg Asset - WA	WA	0	0	0	0	0	0	0	0	0
4098300	415855	CA - January 2010 Storm Costs	OTHER	1,468	0	0	0	0	0	0	0	1,468
4098300	415856	Powerdale Decommissioning Reg Asset - WY	WYP	0	0	0	0	0	0	0	0	0
4098300	415857	ID - Deferred Overburden Costs	OTHER	104	0	0	0	0	0	0	0	104
4098300	415858	WY - Deferred Overburden Costs	WYP	294	0	0	0	294	0	0	0	0
4098300	415859	WY - Deferred Advertising Costs	WYP	0	0	0	0	0	0	0	0	0
4098300	415865	Reg Asset - UT MPA	OTHER	0	0	0	0	0	0	0	0	0
4098300	415867	Reg Asset - CA Solar Feed-in Tariff	OTHER	0	0	0	0	0	0	0	0	0
4098300	415868	Reg Asset - UT - Solar Incentive Program	OTHER	-8,871	0	0	0	0	0	0	0	-8,871
4098300	415870	Deferred Excess Net Power Costs-CA	CA	0	0	0	0	0	0	0	0	0
4098300	415871	Deferred Excess Net Power Costs-WY	WYP	0	0	0	0	0	0	0	0	0
4098300	415872	Deferred Excess Net Power Costs - WY 08	OTHER	0	0	0	0	0	0	0	0	0

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Schedule M
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4098300	415876	Deferred Excess Net PowerCosts - OR	OTHER	-2,907	0	0	0	0	0	0	0	-2,907
4098300	415881	Deferral of Renewable Energy Credit - UT	OTHER	203	0	0	0	0	0	0	0	203
4098300	415883	Deferral of Renewable Energy Credit - WY	OTHER	340	0	0	0	0	0	0	0	340
4098300	415890	ID MEHC 2006 Transistion Costs	IDU	0	0	0	0	0	0	0	0	0
4098300	415891	WY - 2006 Transition Severance Costs	WYP	0	0	0	0	0	0	0	0	0
4098300	415893	OR - MEHC Transition Service Costs	OTHER	0	0	0	0	0	0	0	0	0
4098300	415895	OR RCAC Sept-Dec 07 deferred	OR	0	0	0	0	0	0	0	0	0
4098300	415896	WA - Chehalis Plant Revenue Requirement	WA	0	0	0	0	0	0	0	0	0
4098300	415897	Reg Asset MEHC Transition Service Costs	CA	0	0	0	0	0	0	0	0	0
4098300	415898	Deferred Coal Costs - Naughton Contract	SE	0	0	0	0	0	0	0	0	0
4098300	415900	OR SB 408 Recovery	OTHER	0	0	0	0	0	0	0	0	0
4098300	415902	Reg Asset - UT REC's in Rates - Current	OTHER	0	0	0	0	0	0	0	0	0
4098300	415911	Contra Reg Asset - Naughton Unit $3 - CA	CA	0	0	0	0	0	0	0	0	0
4098300	415912	Contra Reg Asset - Naughton Unit #3 - OR	OTHER	0	0	0	0	0	0	0	0	0
4098300	415913	Contra Reg Asset - Naughton Unit #3 - WA	OTHER	0	0	0	0	0	0	0	0	0
4098300	415914	Reg Asset - UT - Naughton U3 Costs	UT	0	0	0	0	0	0	0	0	0
4098300	415915	Reg Asset - WY - Naughton U3 Costs	WYP	0	0	0	0	0	0	0	0	0
4098300	415926	Reg Liability - Depreciation Decrease -	OTHER	1,256	0	0	0	0	0	0	0	1,256
4098300	415927	Reg Liability - Depreciation Decrease De	WA	0	0	0	0	0	0	0	0	0
4098300	415938	Reg Asset - Carbon Plant Decommissioning	CA	0	0	0	0	0	0	0	0	0
4098300	425100	Deferred Regulatory Expense	IDU	0	0	0	0	0	0	0	0	0
4098300	425105	Reg Asset - OR Asset Sale Gain Giveback	OTHER	142	0	0	0	0	0	0	0	142
4098300	425125	Deferred Coal Cost - Arch	SE	0	0	0	0	0	0	0	0	0
4098300	425205	Misc Def Dr-Prop Damage Repairs	SO	0	0	0	0	0	0	0	0	0
4098300	425215	Unearned Joint Use Pole Contact Revenu	SNPD	0	0	0	0	0	0	0	0	0
4098300	425250	TGS Buyout-SG	SG	15	0	4	1	2	7	1	0	0
4098300	425260	Lakeview Buyout-SG	SG	0	0	0	0	0	0	0	0	0
4098300	425280	Joseph Settlement-SG	SG	0	0	0	0	0	0	0	0	0
4098300	425295	BPA Conservation Rate Credit	SG	0	0	0	0	0	0	0	0	0
4098300	425360	Hermiston Swap	SG	172	3	45	14	25	76	10	0	0
4098300	425380	Idaho Customer Balancing Account	OTHER	0	0	0	0	0	0	0	0	0
4098300	430100	Customer Service / Weatherization	OTHER	9,700	0	0	0	0	0	0	0	9,700
4098300	430111	Reg Asset - SB 1149 Balance Reclass	OTHER	0	0	0	0	0	0	0	0	0
4098300	430112	Reg Asset - Other - Balance Reclass	OTHER	0	0	0	0	0	0	0	0	0
4098300	430113	Reg Asset - Def NPC Balance Reclass	OTHER	0	0	0	0	0	0	0	0	0
4098300	430117	Reg Asset - Current DSM	OTHER	0	0	0	0	0	0	0	0	0
4098300	505115	Sales & Use Tax Accrual	SO	0	0	0	0	0	0	0	0	0

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FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4098300	505125	ACCRUED ROYALTIES	SE	1,151	17	289	87	184	499	75	0	0
4098300	505140	Purchase Card Trans Provision	SO	0	0	0	0	0	0	0	0	0
4098300	505160	CA PUC Fee	CA	0	0	0	0	0	0	0	0	0
4098300	505170	West Valley Contract Termination Fee Acc	SG	0	0	0	0	0	0	0	0	0
4098300	505200	Extraction Tax Paid / Accrued	SE	0	0	0	0	0	0	0	0	0
4098300	505400	Bonus Liability	SO	-208	-5	-57	-16	-28	-91	-12	0	0
4098300	505500	Federal Income Tax Interest	SO	0	0	0	0	0	0	0	0	0
4098300	505510	PMIVacationBonus Adjustment	SE	0	0	0	0	0	0	0	0	0
4098300	505600	Sick Leave Vacation & Personal Time	SO	469	10	128	36	64	204	27	0	0
4098300	505601	Sick Leave Accrual - PMI	SE	1	0	0	0	0	0	0	0	0
4098300	505700	Accrued Retention Bonus	SO	-595	-13	-162	-46	-81	-259	-34	0	0
4098300	605100	Trojan Decomissioning Costs	TROJD	-51	-1	-13	-4	-8	-22	-3	0	0
4098300	605301	Environmental Liability - Regulated	SO	447	10	122	34	61	194	26	0	0
4098300	605710	Reverse Accrued Final Reclamation	OTHER	-4,589	0	0	0	0	0	0	0	-4,589
4098300	605715	Trapper Mine Contract Obligation	SE	281	4	70	21	45	122	18	0	0
4098300	610000	Coal Mine Development-PMI	SE	-85	-1	-21	-6	-14	-37	-6	0	0
4098300	610005	Sec 174 94-98 7 99-00 RAR	SO	0	0	0	0	0	0	0	0	0
4098300	610100	PMIDevt Cost Amort	SE	0	0	0	0	0	0	0	0	0
4098300	610111	PMIBCC Gain/Loss on Assets Disposed	SE	0	0	0	0	0	0	0	0	0
4098300	610114	PMI EITF Pre-Stripping Costs	SE	0	0	0	0	0	0	0	0	0
4098300	610115	PMIOverburden Removal	SE	0	0	0	0	0	0	0	0	0
4098300	610130	781 Shopping Incentive_OR	OTHER	0	0	0	0	0	0	0	0	0
4098300	610135	SB1149 Costs_OR OTHER	OTHER	0	0	0	0	0	0	0	0	0
4098300	610140	Oregon Rate Refund	OTHER	0	0	0	0	0	0	0	0	0
4098300	610141	WA Rate Refunds	OTHER	0	0	0	0	0	0	0	0	0
4098300	610142	Reg Liability - UT Home Energy Lifeline	UT	0	0	0	0	0	0	0	0	0
4098300	610143	Reg Liability - WA Low Energy Program	WA	-1,289	0	0	-1,289	0	0	0	0	0
4098300	610144	Reg Liability - CA California Alternativ	OTHER	0	0	0	0	0	0	0	0	0
4098300	610145	REG LIAB-DSM	OTHER	23,147	0	0	0	0	0	0	0	23,147
4098300	610146	OR Reg Asset/Liability Consolidation	OR	0	0	0	0	0	0	0	0	0
4098300	610148	Reg Liability - Def NPC Balance Reclass	OTHER	0	0	0	0	0	0	0	0	0
4098300	610149	Reg Liability - SB 1149 Balance Reclass	OTHER	0	0	0	0	0	0	0	0	0
4098300	705210	Property Insurance	SO	0	0	0	0	0	0	0	0	0
4098300	705230	West Valley Lease Reduction - WA	WA	0	0	0	0	0	0	0	0	0
4098300	705231	West Valley Lease Reduction - OR	OR	0	0	0	0	0	0	0	0	0
4098300	705232	West Valley Lease Reduction - CA	CA	0	0	0	0	0	0	0	0	0
4098300	705233	West Valley Lease Reduction - ID	IDU	0	0	0	0	0	0	0	0	0

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4098300	705234	West Valley Lease Reduction - WY	WYU	0	0	0	0	0	0	0	0	0
4098300	705235	West Valley Lease Reduction - UT	UT	0	0	0	0	0	0	0	0	0
4098300	705240	CA Alternative Rate for Energy Program(C	OTHER	254	0	0	0	0	0	0	0	254
4098300	705241	Reg Liability - CA California Alternativ	OTHER	0	0	0	0	0	0	0	0	0
4098300	705245	REG LIABILITY - OR DIRECT ACCESS 5 YEAR	OTHER	1,865	0	0	0	0	0	0	0	1,865
4098300	705250	A&G Credit-WA	WA	0	0	0	0	0	0	0	0	0
4098300	705251	A&G Credit-OR	OR	0	0	0	0	0	0	0	0	0
4098300	705252	A&G Credit-CA	CA	0	0	0	0	0	0	0	0	0
4098300	705253	A&G Credit-ID	IDU	0	0	0	0	0	0	0	0	0
4098300	705254	A&G Credit-WY	WYP	0	0	0	0	0	0	0	0	0
4098300	705260	March 2006 Transition Plan costs-WA	WA	0	0	0	0	0	0	0	0	0
4098300	705261	Reg Liability - Sale of renewable Energy	OTHER	0	0	0	0	0	0	0	0	0
4098300	705262	Reg Liability - Sale of REC's-ID	OTHER	0	0	0	0	0	0	0	0	0
4098300	705263	Reg Liability - Sale of REC's-WA	OTHER	0	0	0	0	0	0	0	0	0
4098300	705265	Reg Liab - OR Energy Conservation Charge	OTHER	0	0	0	0	0	0	0	0	0
4098300	705266	Reg Liability - Energy Savings Assistanc	OTHER	51	0	0	0	0	0	0	0	51
4098300	705267	Reg Liability - WA Decoupling Mechanism	OTHER	-452	0	0	0	0	0	0	0	-452
4098300	705301	Reg Liability - OR 2010 Protocol Def	OR	0	0	0	0	0	0	0	0	0
4098300	705305	Reg Liability-CA Gain on Sale of Asset	CA	0	0	0	0	0	0	0	0	0
4098300	705336	Reg Liability - Sale of Renewable Energy	OTHER	303	0	0	0	0	0	0	0	303
4098300	705337	Regulatory Liability - Sale of Renewable	OTHER	0	0	0	0	0	0	0	0	0
4098300	705340	Reg Liability - Excess Income Tax Deferr	OTHER	2,728	0	0	0	0	0	0	0	2,728
4098300	705341	Reg Liability - Excess Income Tax Deferr	OTHER	-1,037	0	0	0	0	0	0	0	-1,037
4098300	705342	Reg Liability - Excess Income Tax Deferr	OTHER	22,246	0	0	0	0	0	0	0	22,246
4098300	705343	Reg Liability - Excess Income Tax Deferr	OTHER	-29,447	0	0	0	0	0	0	0	-29,447
4098300	705344	Reg Liability - Excess Income Tax Deferr	OTHER	137	0	0	0	0	0	0	0	137
4098300	705345	Reg Liability - Excess Income Tax Deferr	OTHER	-9,661	0	0	0	0	0	0	0	-9,661
4098300	705400	Reg Liability - OR Injuries & Damages Re	OR	-22	0	-22	0	0	0	0	0	0
4098300	705420	Reg Liability - CA GHG Allowance Revenue	OTHER	1,147	0	0	0	0	0	0	0	1,147
4098300	705451	Reg Liability - OR Property Insurance Re	OR	-6,974	0	-6,974	0	0	0	0	0	0
4098300	705453	Reg Liability - ID Property Insurance Re	IDU	114	0	0	0	0	0	114	0	0
4098300	705455	Reg Liability - WY Property Insurance Re	WYP	350	0	0	0	350	0	0	0	0
4098300	705500	Reg Liability - Powerdale Decommissionin	UT	0	0	0	0	0	0	0	0	0
4098300	705514	Regulatory Liability - OR Deferred Exces	OTHER	0	0	0	0	0	0	0	0	0
4098300	705515	Regulatory Liability - OR Deferred Exces	OTHER	5,969	0	0	0	0	0	0	0	5,969
4098300	705517	Regulatory Liability - UT Deferred Exces	OTHER	0	0	0	0	0	0	0	0	0
4098300	705518	Regulatory Liability - WA Deferred Exces	OTHER	0	0	0	0	0	0	0	0	0

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4098300	705519	Regulatory Liability - WA Deferred Exces	OTHER	-9,202	0	0	0	0	0	0	0	-9,202
4098300	705521	Regulatory Liability - WY Deferred Exces	OTHER	-8,879	0	0	0	0	0	0	0	-8,879
4098300	705522	Regulatory Liability - UT REC's in Rates	OTHER	0	0	0	0	0	0	0	0	0
4098300	705523	Regulatory Liability - WA RECS in Rates	OTHER	0	0	0	0	0	0	0	0	0
4098300	705525	Regulatory Liability - OR RECS in Rates	OTHER	0	0	0	0	0	0	0	0	0
4098300	705526	Regulatory Liability - CA Solar Feed-in	OTHER	0	0	0	0	0	0	0	0	0
4098300	705527	Regulatory Liability - CA Solar Feed-in	OTHER	-447	0	0	0	0	0	0	0	-447
4098300	705530	Regulatory Liability - UT Solar Feed-in	OTHER	0	0	0	0	0	0	0	0	0
4098300	705531	Regulatory Liability - UT Solar Feed-in	OTHER	3,227	0	0	0	0	0	0	0	3,227
4098300	705536	Regulatory Liability - CA GreenHouse Gas	OTHER	0	0	0	0	0	0	0	0	0
4098300	705600	RegLiability - OR 2012 GRC Giveback	OTHER	0	0	0	0	0	0	0	0	0
4098300	705700	Reg Liability - Current Reclass - Other	OTHER	0	0	0	0	0	0	0	0	0
4098300	715050	Microsoft Software License Liability	SO	0	0	0	0	0	0	0	0	0
4098300	715100	MCI FOG Wire Lease	WYP	0	0	0	0	0	0	0	0	0
4098300	715105	MCI FOG Wire Lease	SG	-466	-7	-121	-37	-68	-205	-27	0	0
4098300	715350	Misc. Deferred Credits	SO	0	0	0	0	0	0	0	0	0
4098300	715720	NW Power Act-WA	OTHER	-451	0	0	0	0	0	0	0	-451
4098300	715810	Chehalis WA EFSEC C02 Mitigation Obligat	SG	-125	-2	-32	-10	-18	-55	-7	0	0
4098300	720200	Deferred Comp Plan Benefits-PPL	SO	0	0	0	0	0	0	0	0	0
4098300	720300	Pension / Retirement (Accrued / Prepaid)	SO	-144	-3	-39	-11	-20	-62	-8	0	0
4098300	720400	Suppl. Exec. Retirement Plan (SERP)	SO	0	0	0	0	0	0	0	0	0
4098300	720550	Accrued CIC Severence	SO	0	0	0	0	0	0	0	0	0
4098300	720560	Pension Liability - UMWA Withdrawal Obli	SE	0	0	0	0	0	0	0	0	0
4098300	740100	Post Merger Loss-Reacquired Debt	SNP	585	12	154	43	79	262	34	0	0
4098300	910245	Contra Receivable from Joint Owners	SO	-257	-6	-70	-20	-35	-112	-15	0	0
4098300	910530	Injuries and Damages Reserve	SO	0	0	0	0	0	0	0	0	0
4098300	910560	SMUD Revenue Imputation-UT reg liab	UT	0	0	0	0	0	0	0	0	0
4098300	910905	Bridger Coal Company Underground Mine Co	SE	939	14	236	71	150	407	62	0	0
4098300	910910	PMIBridger Section 471 Adj	SE	0	0	0	0	0	0	0	0	0
4098300	920110	PMIWY Extraction Tax	SE	323	5	81	24	52	140	21	0	0
4098300 Total				**1,203,201**	**25,587**	**310,555**	**102,316**	**164,219**	**523,856**	**68,297**	**251**	**8,121**
4099200	105127	Book Depreciation Allocated to Medicare	SCHMDEXP	-19	0	-5	-2	-3	-8	-1	0	0
4099200	110200	Tax Depletion - Deer Creek	SE	0	0	0	0	0	0	0	0	0
4099200	1102051	TAX PERCENTAGE DEPLETION - DEDUCTION	SE	0	0	0	0	0	0	0	0	0
4099200	120100	Preferred Dividend - PPL	SNP	107	2	28	8	14	48	6	0	0
4099200	120200	Trapper Mine Dividend Deduction	SE	0	0	0	0	0	0	0	0	0

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4099200	130560	MEHC Insurance Services-Receivable	SO	0	0	0	0	0	0	0	0	0
4099200	130600	Tax Exempt Interest (No AMT)	SO	0	0	0	0	0	0	0	0	0
4099200	130605	Tax Exempt Interest - CA IOU	CA	0	0	0	0	0	0	0	0	0
4099200	130910	SPI 404(K) Contribution	SO	0	0	0	0	0	0	0	0	0
4099200	305100	Amort of Projects-Klamath Engineering	DGP	0	0	0	0	0	0	0	0	0
4099200	620100	2004 JCA-Qualified Prod Activities Deduc	SG	0	0	0	0	0	0	0	0	0
4099200	620101	PMI 2004 JCA-Qualified Prod Activities D	SE	0	0	0	0	0	0	0	0	0
4099200	720105	MEDICARE SUBSIDY	SO	0	0	0	0	0	0	0	0	0
4099200	910900	PMIDepletion	SE	0	0	0	0	0	0	0	0	0
4099200	910918	PMI Overriding Royalty	SE	0	0	0	0	0	0	0	0	0
4099200	920105	PMI Tax Exempt Interest Income	SE	0	0	0	0	0	0	0	0	0
4099200 Total				**87**	**2**	**23**	**6**	**12**	**39**	**5**	**0**	**0**
4099300	105101	Capitalized Labor Cost for Powertax Inpu	SO	0	0	0	0	0	0	0	0	0
4099300	105122	Repair Deduction	SG	146,685	2,254	38,171	11,576	21,453	64,538	8,651	42	0
4099300	105125	Tax Depreciation	TAXDEPR	590,718	11,448	155,203	34,383	80,994	264,466	33,698	130	0
4099300	105126	PMITax Depreciation	SE	6,227	91	1,563	468	995	2,700	408	2	0
4099300	105137	Capitalized Depreciation	SO	5,977	133	1,627	460	813	2,600	343	1	0
4099300	1051411	AFUDC - DEBT	SNP	25,391	531	6,676	1,879	3,445	11,391	1,459	5	5
4099300	1051412	AFUDC - Equity	SNP	49,314	1,031	12,966	3,649	6,692	22,123	2,834	10	9
4099300	105143	Basis Intangible Difference	SO	223	5	61	17	30	97	13	0	0
4099300	105147	Sec 1031 Like Kind Exchange	SO	0	0	0	0	0	0	0	0	0
4099300	105148	Mine Safety Sec. 179E Election - PPW	SE	0	0	0	0	0	0	0	0	0
4099300	105149	Mine Safety Sec. 179E Election - PMI	SE	0	0	0	0	0	0	0	0	0
4099300	105152	Gain/(Loss) on Prop Dispositions	GPS	16,378	366	4,457	1,261	2,227	7,124	940	3	0
4099300	105153	Contract Liability Basis Adjustment -Che	SG	-125	-2	-32	-10	-18	-55	-7	0	0
4099300	105165	Coal Mine Development	SE	0	0	0	0	0	0	0	0	0
4099300	105171	PMI Coal Mine Receding Face (Extension)	SE	659	10	165	50	105	286	43	0	0
4099300	105175	Removal Cost (net of salvage)	GPS	50,126	1,119	13,642	3,859	6,815	21,804	2,877	10	0
4099300	105181	Stm Rts Blundell Geothermal Tax Depr	SG	0	0	0	0	0	0	0	0	0
4099300	105185	Repair Allowance 3115	DGP	0	0	0	0	0	0	0	0	0
4099300	105220	Cholla GE Safe Harbor Lease	SG	0	0	0	0	0	0	0	0	0
4099300	1052203	Cholla SHL-NOPA (Lease Amortization)	SG	340	5	88	27	50	149	20	0	0
4099300	105470	Book Gain/Loss on Land Sales	GPS	1,578	35	430	122	215	687	91	0	0
4099300	110200	Depletion - Tax Percentage Deduction	SE	0	0	0	0	0	0	0	0	0
4099300	1102051	Tax Percentage Depletion - Deduction	SE	32	0	8	2	5	14	2	0	0
4099300	120105	Willow Wind Account Receivable	WA	0	0	0	0	0	0	0	0	0

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4099300	205025	PMI - Fuel Cost Adjustment	SE	1,587	23	398	119	254	688	104	1	0
4099300	205200	Coal M&S Inventory Write-Off	SNPD	1,548	56	414	95	158	745	79	0	0
4099300	205205	Inventory Reserve - PMI	SE	129	2	32	10	21	56	8	0	0
4099300	205411	PMISEC 263A Adjustment	SE	-5,264	-77	-1,321	-396	-841	-2,282	-345	-2	0
4099300	210000	PREPAID IBEW 57 MEDICAL	SO	0	0	0	0	0	0	0	0	0
4099300	210100	Prepaid Taxes-OR PUC	OR	-156	0	-156	0	0	0	0	0	0
4099300	210105	Self Insured Health Benefit	SO	0	0	0	0	0	0	0	0	0
4099300	210110	Prepaid Taxes-WA UTC	WA	0	0	0	0	0	0	0	0	0
4099300	210120	Prepaid Taxes-UT PUC	UT	-71	0	0	0	0	-71	0	0	0
4099300	210130	Prepaid Taxes-ID PUC	IDU	40	0	0	0	0	0	40	0	0
4099300	210140	Prepaid Taxes-WY PSC	WYP	0	0	0	0	0	0	0	0	0
4099300	210150	Prepaid Taxes-CA Property Taxes-GPS allo	GPS	0	0	0	0	0	0	0	0	0
4099300	210160	Prepaid Taxes-OR Property Taxes-GPS allo	GPS	0	0	0	0	0	0	0	0	0
4099300	210180	OTHER PREPAIDS	SO	-821	-18	-223	-63	-112	-357	-47	0	0
4099300	210185	Prepaid Aircraft Maintenance Costs	SG	13	0	3	1	2	6	1	0	0
4099300	210190	Prepaid Water Rights	SG	0	0	0	0	0	0	0	0	0
4099300	210195	Prepaid Surety Bond Costs	SO	0	0	0	0	0	0	0	0	0
4099300	210200	Prepaid Taxes-property taxes	GPS	0	0	0	0	0	0	0	0	0
4099300	287396	Regulatory Liabilities - Interim Provisi	OTHER	0	0	0	0	0	0	0	0	0
4099300	287616	Regulatory Assets - Interim Provisions	OTHER	0	0	0	0	0	0	0	0	0
4099300	305100	Amort of Projects-Klamath Engineering	DGP	0	0	0	0	0	0	0	0	0
4099300	310102	Fixed Asset-Book/Tax - IGC	SE	0	0	0	0	0	0	0	0	0
4099300	320210	Research & Exper. Sec. 174 Amort.	SO	0	0	0	0	0	0	0	0	0
4099300	320271	Contra Reg Asset - Pension Plan CTG	SO	1,641	37	447	126	223	714	94	0	0
4099300	320279	Reg Liability - FAS 158 Post Retirement	SO	-10,971	-245	-2,986	-845	-1,492	-4,772	-630	-2	0
4099300	320285	Reg Asset-Post Employment Costs	SO	-428	-10	-116	-33	-58	-186	-25	0	0
4099300	320290	LT Prepaid IBEW 57 Pension Contribution	OTHER	0	0	0	0	0	0	0	0	0
4099300	320291	Prepaid IBEw 57 Pension Contribution - C	OTHER	0	0	0	0	0	0	0	0	0
4099300	415110	Def Reg Asset-Transmission Srvc Deposit	SG	-1,520	-23	-396	-120	-222	-669	-90	0	0
4099300	415120	DEFERRED REG ASSET - FOOTE CREEK CONTRAC	SG	0	0	0	0	0	0	0	0	0
4099300	415200	REG ASSET - OR TRANSPORTATION ELECTRIFIC	OTHER	390	0	0	0	0	0	0	0	390
4099300	415300	Hazardous Waste Clean-up Costs	SO	1,876	42	510	144	255	816	108	0	0
4099300	415301	Hazardous Waste Clean-up Costs-WA	WA	0	0	0	0	0	0	0	0	0
4099300	415410	Reg Asset - Energy West Mining	SE	-1,004	-15	-252	-75	-160	-435	-66	0	0
4099300	415411	ContraRA DeerCreekAband CA	CA	17	17	0	0	0	0	0	0	0
4099300	415412	ContraRA DeerCreekAband ID	IDU	-415	0	0	0	0	0	-415	0	0
4099300	415413	ContraRA DeerCreekAband OR	OR	-1,619	0	-1,619	0	0	0	0	0	0

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4099300	415414	ContraRA DeerCreekAband UT	UT	-8	0	0	0	0	-8	0	0	0
4099300	415415	ContraRA DeerCreekAband WA	WA	77	0	0	77	0	0	0	0	0
4099300	415416	ContraRA DeerCreekAband WY	WYU	0	0	0	0	0	0	0	0	0
4099300	415417	Contra RA UMWA Pension CA	OTHER	7	0	0	0	0	0	0	0	7
4099300	415418	Contra RA UMWA Pension ID	OTHER	0	0	0	0	0	0	0	0	0
4099300	415419	Contra RA UMWA Pension OR	OTHER	0	0	0	0	0	0	0	0	0
4099300	415420	Contra RA UMWA Pension UT	OTHER	0	0	0	0	0	0	0	0	0
4099300	415421	Contra RA UMWA Pension WA	OTHER	33	0	0	0	0	0	0	0	33
4099300	415422	Contra RA UMWA Pension WY	OTHER	0	0	0	0	0	0	0	0	0
4099300	415431	Reg Asset - WA Transportation Electrific	OTHER	39	0	0	0	0	0	0	0	39
4099300	415501	Cholla Plt Transact Costs- APS Amort - I	IDU	0	0	0	0	0	0	0	0	0
4099300	415502	Cholla Plt Transact Costs- APS Amort - O	OR	0	0	0	0	0	0	0	0	0
4099300	415530	Reg Asset - ID 2017 Protocol - MSP Defer	IDU	150	0	0	0	0	0	150	0	0
4099300	415531	Reg Asset - UT 2017 Protocol - MSP Defer	UT	4,400	0	0	0	0	4,400	0	0	0
4099300	415532	Reg Asset - WY 2017 Protocol - MSP Defer	WYP	1,600	0	0	0	1,600	0	0	0	0
4099300	415545	Reg Asset - WA Merwin Project	OTHER	0	0	0	0	0	0	0	0	0
4099300	415585	Reg Asset - OR Sch 203 - Black Cap	OTHER	0	0	0	0	0	0	0	0	0
4099300	415655	CA GHG Allowance	OTHER	0	0	0	0	0	0	0	0	0
4099300	415675	Reg Asset - UT - Deferred Stock Redempti	OTHER	-83	0	0	0	0	0	0	0	-83
4099300	415676	Reg Asset - WY - Deferred Stock Redempti	OTHER	-28	0	0	0	0	0	0	0	-28
4099300	415677	Reg Asset - Pref Stock Redemp Loss WA	OTHER	-13	0	0	0	0	0	0	0	-13
4099300	415680	Deferred Intervenor Funding Grants-OR	OTHER	443	0	0	0	0	0	0	0	443
4099300	415700	Reg Liability BPA balancing accounts-OR	OTHER	0	0	0	0	0	0	0	0	0
4099300	415701	CA Deferred Intervenor Funding	OTHER	2	0	0	0	0	0	0	0	2
4099300	415703	Goodnoe Hills Liquidation Damages - WY	WYP	0	0	0	0	0	0	0	0	0
4099300	415705	Reg Liability - Tax Revenue Adjustment -	WYP	0	0	0	0	0	0	0	0	0
4099300	415720	Reg Asset - Community Solar - OR	OTHER	160	0	0	0	0	0	0	0	160
4099300	415750	Reg Assets BPA balancing accounts-IDU	OTHER	0	0	0	0	0	0	0	0	0
4099300	415801	RTO Grid West N/R Allowance	SG	0	0	0	0	0	0	0	0	0
4099300	415803	RTO Grid West N/R Allowance w/o WA	WA	0	0	0	0	0	0	0	0	0
4099300	415804	OR RTO Grid West N/R	OR	0	0	0	0	0	0	0	0	0
4099300	415815	Insurance Reserve	SO	-229	-5	-62	-18	-31	-100	-13	0	0
4099300	415820	Contra Pension Reg Asset MMT & CTG _OR	OR	504	0	504	0	0	0	0	0	0
4099300	415821	Contra Pension Reg Asset MMT & CTG _WY	WYP	0	0	0	0	0	0	0	0	0
4099300	415823	Contra Pension Reg Asset CTG - UT	UT	0	0	0	0	0	0	0	0	0
4099300	415824	Contra Pension Reg Asset MMT & CTG _CA	CA	45	45	0	0	0	0	0	0	0
4099300	415825	Contra Pension Reg Asset CTG - WA	WA	0	0	0	0	0	0	0	0	0

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FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4099300	415845	Reg Asset - OR Sch 94 Distribution Safet	OTHER	0	0	0	0	0	0	0	0	0
4099300	415850	Unrecovered Plant Powerdale	SG	0	0	0	0	0	0	0	0	0
4099300	415851	Powerdale Hydro Decom Reg Asset - CA	CA	0	0	0	0	0	0	0	0	0
4099300	415852	Powerdale Decommissioning Reg Asset - ID	IDU	0	0	0	0	0	0	0	0	0
4099300	415853	Powerdale Decommissioning Reg Asset - OR	OR	0	0	0	0	0	0	0	0	0
4099300	415854	Powerdale Decommissioning Reg Asset - WA	WA	0	0	0	0	0	0	0	0	0
4099300	415855	Ca - January 2010 Storm Costs	OTHER	0	0	0	0	0	0	0	0	0
4099300	415856	Powerdale Decommissioning Reg Asset - WY	WYP	0	0	0	0	0	0	0	0	0
4099300	415857	ID - Deferred Overburden Costs	OTHER	0	0	0	0	0	0	0	0	0
4099300	415858	WY - Deferred Overburden Costs	WYP	0	0	0	0	0	0	0	0	0
4099300	415859	WY - Deferred Advertising Costs	OTHER	0	0	0	0	0	0	0	0	0
4099300	415862	Reg Asset - CA Mobile Home Park Conversi	OTHER	7	0	0	0	0	0	0	0	7
4099300	415863	Reg Asset - UT Subscriber Solar Program	UT	107	0	0	0	0	107	0	0	0
4099300	415865	Reg Asset - Utah MPA	OTHER	0	0	0	0	0	0	0	0	0
4099300	415866	Reg Asset - OR Solar Feed-in Tariff	OTHER	-70	0	0	0	0	0	0	0	-70
4099300	415869	Reg Asset - CA Deferred Net Power Costs	OTHER	0	0	0	0	0	0	0	0	0
4099300	415870	CA Def Excess NPC	CA	1,965	1,965	0	0	0	0	0	0	0
4099300	415874	Deferred Excess Net Power Costs - WY 08	OTHER	7,303	0	0	0	0	0	0	0	7,303
4099300	415875	Deferred Excess Net Power Costs - UT	OTHER	32,906	0	0	0	0	0	0	0	32,906
4099300	415876	Deferred Excess Net Power Costs - OR	OTHER	0	0	0	0	0	0	0	0	0
4099300	415878	REG ASSET - UT LIQUIDATED DAMAGES NAUGHT	UT	-35	0	0	0	0	-35	0	0	0
4099300	415879	Reg Asset - WY Liquidation Damages N2	WYP	-6	0	0	0	-6	0	0	0	0
4099300	415882	Deferral of Renewable Energy Credit - WA	OTHER	-21	0	0	0	0	0	0	0	-21
4099300	415884	Reg Asset - Current Reclass - Other	OTHER	0	0	0	0	0	0	0	0	0
4099300	415885	Reg Asset - Noncurrent Reclass - Other	OTHER	-15	0	0	0	0	0	0	0	-15
4099300	415886	Reg Asset - ID Deferred Excess Net Power	OTHER	0	0	0	0	0	0	0	0	0
4099300	415888	Reg Asset - UT Deferred Excess Net Power	OTHER	0	0	0	0	0	0	0	0	0
4099300	415892	Deferred Excess Net Power Costs - ID 09	OTHER	12,033	0	0	0	0	0	0	0	12,033
4099300	415893	OR - MEHC Transition Service Costs	OTHER	0	0	0	0	0	0	0	0	0
4099300	415894	Reg Asset - REC Sales Deferral - CA - No	OTHER	0	0	0	0	0	0	0	0	0
4099300	415896	WA - Chehalis Plant Revenue Requirement	WA	0	0	0	0	0	0	0	0	0
4099300	415897	Reg Asset MEHC Transition Service Costs	CA	0	0	0	0	0	0	0	0	0
4099300	415898	Deferred Coal Costs - Naughton Contract	SE	0	0	0	0	0	0	0	0	0
4099300	415900	OR SB 408 Recovery	OTHER	0	0	0	0	0	0	0	0	0
4099300	415901	Reg Asset - WY Deferred Excess Net Power	OTHER	0	0	0	0	0	0	0	0	0
4099300	415903	Reg Asset _ REC Sales Deferral - WA	OTHER	0	0	0	0	0	0	0	0	0
4099300	415904	Reg Asset - WY REC's in Rates - Current	OTHER	0	0	0	0	0	0	0	0	0

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FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4099300	415905	Reg Asset - OR REC's in Rates - Current	OTHER	0	0	0	0	0	0	0	0	0
4099300	415906	Reg Asset - REC Sales Deferral - OR - No	OTHER	-179	0	0	0	0	0	0	0	-179
4099300	415907	Reg Asset - CA Solar Feed-in Tariff - Cu	OTHER	0	0	0	0	0	0	0	0	0
4099300	415908	Reg Asset - OR Solar Feed-In Tariff - Cu	OTHER	0	0	0	0	0	0	0	0	0
4099300	415910	Reg Asset - Naughton Unit #3 Costs	OTHER	0	0	0	0	0	0	0	0	0
4099300	415917	Reg Asset - Naughton Unit #3 Costs - CA	OTHER	0	0	0	0	0	0	0	0	0
4099300	415918	Reg Asset - RPS Compliance Purchases	OTHER	0	0	0	0	0	0	0	0	0
4099300	415920	Reg Asset - Depreciation Increase - ID	IDU	73	0	0	0	0	0	73	0	0
4099300	415921	Reg Asset - Depreciation Increase - UT	UT	-128	0	0	0	0	-128	0	0	0
4099300	415922	Reg Asset - Depreciation Increase - WY	WYP	-442	0	0	0	-442	0	0	0	0
4099300	415923	Reg Asset - Carbon Unrecovered Plant - I	IDU	-479	0	0	0	0	0	-479	0	0
4099300	415924	Reg Asset - Carbon Unrecovered Plant - U	UT	-3,445	0	0	0	0	-3,445	0	0	0
4099300	415925	Reg Asset - Carbon Unrecovered Plant - W	WYP	-1,158	0	0	0	-1,158	0	0	0	0
4099300	415930	Reg Asset - Carbon Decommissioning - ID	IDU	0	0	0	0	0	0	0	0	0
4099300	415931	Reg Asset - Carbon Decommissioning - UT	UT	0	0	0	0	0	0	0	0	0
4099300	415932	Reg Asset - Carbon Decommissioning - WY	WYP	0	0	0	0	0	0	0	0	0
4099300	415933	Reg Liability - Contra - Carbon Decommis	IDU	-35	0	0	0	0	0	-35	0	0
4099300	415934	Reg Liability - Contra - Carbon Decommis	UT	-250	0	0	0	0	-250	0	0	0
4099300	415935	Reg Liability - Contra - Carbon Decommis	WYP	-624	0	0	0	-624	0	0	0	0
4099300	415936	REG ASSET - CARBON PLANT DECOMMISSIONING	SG	0	0	0	0	0	0	0	0	0
4099300	425100	Deferred Regulatory Expense-IDU	IDU	40	0	0	0	0	0	40	0	0
4099300	425102	Reg Asset - CA GreenHouse Gas Allowance	OTHER	0	0	0	0	0	0	0	0	0
4099300	425103	Reg Asset - Other Regulatory Assets - Cu	OTHER	0	0	0	0	0	0	0	0	0
4099300	425104	Reg Asset - OR Asset Sale Gain Giveback	OTHER	0	0	0	0	0	0	0	0	0
4099300	425205	Misc Def Dr-Prop Damage Repairs	SO	0	0	0	0	0	0	0	0	0
4099300	425210	Amort of Debt Disc & Exp	SNP	0	0	0	0	0	0	0	0	0
4099300	425215	Unearned Joint Use Pole Contact Revenue	SNPD	-22	-1	-6	-1	-2	-11	-1	0	0
4099300	425225	Duke/Hermiston Contract Renegotiation	SG	0	0	0	0	0	0	0	0	0
4099300	425295	BPA Conservation Rate Credit	SG	0	0	0	0	0	0	0	0	0
4099300	425380	Idaho Customer Balancing Account	OTHER	0	0	0	0	0	0	0	0	0
4099300	425400	UT Kalamath Relicensing Costs	OTHER	-3,603	0	0	0	0	0	0	0	-3,603
4099300	425700	Trojan Special Assessment -DOE-IRS	TROJD	0	0	0	0	0	0	0	0	0
4099300	425800	Allowance for Doubtful A/C-Grid West W/O	SG	0	0	0	0	0	0	0	0	0
4099300	430100	Customer Service / Weatherization	OTHER	0	0	0	0	0	0	0	0	0
4099300	430110	Reg Asset balance reclass	OTHER	23,147	0	0	0	0	0	0	0	23,147
4099300	430111	Reg Asset - SB 1149 Balance Reclass	OTHER	0	0	0	0	0	0	0	0	0
4099300	430112	Reg Asset - Other - Balance Reclass	OTHER	994	0	0	0	0	0	0	0	994

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FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4099300	430113	Reg Asset - Def NPC Balance Reclass	OTHER	0	0	0	0	0	0	0	0	0
4099300	505115	Sales & Use Tax Accrual	SO	0	0	0	0	0	0	0	0	0
4099300	505125	Accrued Royalties	SE	0	0	0	0	0	0	0	0	0
4099300	505140	Purchase Card Trans Provision	SO	0	0	0	0	0	0	0	0	0
4099300	505170	West Valley Contract Termination Fee Acc	SG	0	0	0	0	0	0	0	0	0
4099300	505400	Bonus Liability	SO	0	0	0	0	0	0	0	0	0
4099300	505510	Vacation Accrual - PMI	SE	11	0	3	1	2	5	1	0	0
4099300	505520	PMI Bonus Accrual	SE	0	0	0	0	0	0	0	0	0
4099300	505600	IGC Vacation Accrual	SO	0	0	0	0	0	0	0	0	0
4099300	605101	Trojan Decommissioning Costs - WA	WA	0	0	0	0	0	0	0	0	0
4099300	605102	Trojan Decommissioning Costs - OR	OR	0	0	0	0	0	0	0	0	0
4099300	605103	ARO/Reg Diff - Trojan - WA	WA	-3	0	0	-3	0	0	0	0	0
4099300	605710	Reverse Accrued Final Reclamation	OTHER	0	0	0	0	0	0	0	0	0
4099300	610000	PMI Coal Mine Development	SE	0	0	0	0	0	0	0	0	0
4099300	610100	PMIDEVT COST AMORT	SE	-379	-6	-95	-29	-61	-165	-25	0	0
4099300	6101001	AMORT NOPAS 99-00 RAR	SO	39	1	11	3	5	17	2	0	0
4099300	610110	Ptax NOPAs	SO	0	0	0	0	0	0	0	0	0
4099300	610111	Bridger Coal Company Gain/Loss on Assets	SE	129	2	32	10	21	56	8	0	0
4099300	610114	PMI EITF Pre Stripping Costs	SE	-3,298	-48	-828	-248	-527	-1,430	-216	-1	0
4099300	610130	781 Shopping Incentive_OR	OTHER	0	0	0	0	0	0	0	0	0
4099300	610135	SB1149 Costs_OR OTHER	OTHER	0	0	0	0	0	0	0	0	0
4099300	610140	OR Rate Refunds	OTHER	0	0	0	0	0	0	0	0	0
4099300	610141	WA Rate Refunds	OTHER	0	0	0	0	0	0	0	0	0
4099300	610142	Reg. Liability - UT Home Energy Lifeline	UT	88	0	0	0	0	88	0	0	0
4099300	610143	REG LIABILITY - WA LOW ENERGY PROGRAM	WA	0	0	0	0	0	0	0	0	0
4099300	610145	REG LIAB-DSM	OTHER	0	0	0	0	0	0	0	0	0
4099300	610146	OR Reg Asset/Liability Consolidation	OR	0	0	0	0	0	0	0	0	0
4099300	610148	Reg Liability - Def NPC Balance Reclass	OTHER	0	0	0	0	0	0	0	0	0
4099300	610149	Reg Liability - SB 1149 Balance Reclass	OTHER	0	0	0	0	0	0	0	0	0
4099300	705200	Oregon Gain on Sale of Halsey-OR	OTHER	0	0	0	0	0	0	0	0	0
4099300	705210	Property Insurance(Injuries & Damages)	SO	0	0	0	0	0	0	0	0	0
4099300	705232	CA West Valley Lease Reduction	CA	0	0	0	0	0	0	0	0	0
4099300	705233	West Valley Lease Reduction - ID	IDU	0	0	0	0	0	0	0	0	0
4099300	705234	West Valley Lease Reduction - WY	WYP	0	0	0	0	0	0	0	0	0
4099300	705235	UT West Valley Lease Reduction	UT	0	0	0	0	0	0	0	0	0
4099300	705250	A&G Credit - WA	WA	0	0	0	0	0	0	0	0	0
4099300	705251	A&G Credit-OR	OR	0	0	0	0	0	0	0	0	0

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FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4099300	705252	A&G Credit-CA	CA	0	0	0	0	0	0	0	0	0
4099300	705253	A&G Credit - ID	IDU	0	0	0	0	0	0	0	0	0
4099300	705254	A&G Credit - WY	WYP	0	0	0	0	0	0	0	0	0
4099300	705261	Reg Liability - Sale of Renewable Energy	OTHER	0	0	0	0	0	0	0	0	0
4099300	705265	Reg Liab - OR Energy Conservation Charge	OTHER	-131	0	0	0	0	0	0	0	-131
4099300	705300	Reg. Liability - Deferred Benefit_Arch S	SE	0	0	0	0	0	0	0	0	0
4099300	705305	Reg Liability-CA Gain on Sale of Asset	CA	0	0	0	0	0	0	0	0	0
4099300	705310	Reg Liability-UT Gain on Sale of Asset	UT	0	0	0	0	0	0	0	0	0
4099300	705320	Reg Liability-ID Gain on Sale of Asset	IDU	0	0	0	0	0	0	0	0	0
4099300	705330	Reg Liability-WY Gain on Sale of Asset	WYP	0	0	0	0	0	0	0	0	0
4099300	705337	Reg Liability - Sale of Renewable Energy	OTHER	-86	0	0	0	0	0	0	0	-86
4099300	705454	Reg Liability - UT Property Insurance Re	UT	-1,206	0	0	0	0	-1,206	0	0	0
4099300	705534	Regulatory Liability - OR Asset Sale Gai	OTHER	0	0	0	0	0	0	0	0	0
4099300	705537	Regulatory Liability - Other Reg Liabili	OTHER	0	0	0	0	0	0	0	0	0
4099300	705700	Reg Liability - Current Reclass - Other	OTHER	0	0	0	0	0	0	0	0	0
4099300	705755	Reg Liability - Non current Reclass - Ot	OTHER	15	0	0	0	0	0	0	0	15
4099300	715050	Microsoft Software License Liability	SO	0	0	0	0	0	0	0	0	0
4099300	715100	University of WY Contract Amort.	WYP	0	0	0	0	0	0	0	0	0
4099300	715350	Misc Deferred Credits	SO	0	0	0	0	0	0	0	0	0
4099300	715800	Redding Renegotiated Contract	SG	0	0	0	0	0	0	0	0	0
4099300	720100	FAS 106 Accruals	SO	0	0	0	0	0	0	0	0	0
4099300	720200	Deferred Comp Plan Benefits-PPL	SO	-70	-2	-19	-5	-9	-30	-4	0	0
4099300	720300	PENSION / RETIREMENT ACCRUAL - CASH BASI	SO	0	0	0	0	0	0	0	0	0
4099300	720400	SUPPL. EXEC. RETIREMENT PLAN (SERP)	SO	0	0	0	0	0	0	0	0	0
4099300	720500	Severance Accrual	SO	257	6	70	20	35	112	15	0	0
4099300	720550	Accrued CIC Severence	SO	0	0	0	0	0	0	0	0	0
4099300	720800	FAS 158 Pension Liability	SO	27,952	624	7,607	2,152	3,801	12,159	1,604	6	0
4099300	720805	FAS 158 - Funded Pension Asset	SO	0	0	0	0	0	0	0	0	0
4099300	720810	FAS 158 Post-Retirement Liability	SO	9,621	215	2,618	741	1,308	4,185	552	2	0
4099300	720815	FAS 158 Post Retirement Liability	SO	-1,686	-38	-459	-130	-229	-733	-97	0	0
4099300	740100	Post Merger Loss-Reacquired Debt	SNP	0	0	0	0	0	0	0	0	0
4099300	910240	190LEGAL RESERVE	SO	0	0	0	0	0	0	0	0	0
4099300	910530	Injuries and Damages Reserve	SO	-10,316	-230	-2,807	-794	-1,403	-4,487	-592	-2	0
4099300	910560	283SMUD REVENUE IMPUTATION-UT REG LIAB	OTHER	0	0	0	0	0	0	0	0	0
4099300	910905	PMI Underground Mine Cost Depletion	SE	0	0	0	0	0	0	0	0	0
4099300	910925	CA Refund	OTHER	0	0	0	0	0	0	0	0	0
4099300	920110	PMI WY Extraction Tax	SE	0	0	0	0	0	0	0	0	0

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FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4099300 Total				974,596	19,344	236,328	58,483	124,127	401,276	51,173	205	73,265
Grand Total				2,180,443	44,989	547,600	161,002	288,708	926,284	119,622	456	81,386

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Deferred Income Tax Expense
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4101000	100105	190FAS 109 DEF TAX LIAB WA-NUTIL	WA	0	0	0	0	0	0	0	0	0
4101000	105101	Capitalized Labor Cost for Powertax Inpu	SO	0	0	0	0	0	0	0	0	0
4101000	105121	282PMI Book Depreciation	SE	0	0	0	0	0	0	0	0	0
4101000	105122	Repair Deduction	SG	36,065	554	9,385	2,846	5,275	15,868	2,127	10	0
4101000	105125	Tax Depreciation	TAXDEPR	145,237	2,815	38,159	8,454	19,914	65,023	8,285	32	0
4101000	105126	282DIT PMIDepreciation-Tax	SE	1,531	22	384	115	245	664	100	0	0
4101000	105137	Capitalized Depreciation	SO	1,470	33	400	113	200	639	84	0	0
4101000	105141	AFUDC Debt	SNP	6,243	131	1,641	462	847	2,801	359	1	1
4101000	1051411	AFUDC Equity	SNP	12,125	254	3,188	897	1,645	5,439	697	3	2
4101000	105143	282Basis Intangible Difference	SO	55	1	15	4	7	24	3	0	0
4101000	105147	Sec 1031 Like Kind Exchange	SO	0	0	0	0	0	0	0	0	0
4101000	105148	Mine Safety Sec. 179E Election - PPW	SE	0	0	0	0	0	0	0	0	0
4101000	105149	Mine Safety Sec. 179E Election - PMI	SE	0	0	0	0	0	0	0	0	0
4101000	105152	Gain / (Loss) on Prop. Disposition	GPS	4,027	90	1,096	310	548	1,752	231	1	0
4101000	105153	Contract Liability Basis Adjustment -Che	SG	-31	0	-8	-2	-4	-14	-2	0	0
4101000	105165	Coal Mine Development	SE	0	0	0	0	0	0	0	0	0
4101000	105170	Coal Mine Extension	SE	0	0	0	0	0	0	0	0	0
4101000	105171	PMI Coal Mine Extension Costs	SE	162	2	41	12	26	70	11	0	0
4101000	105175	Cost of Removal	GPS	12,324	275	3,354	949	1,676	5,361	707	3	0
4101000	1052203	Cholla SHL NOPA (Lease Amortization)	SG	84	1	22	7	12	37	5	0	0
4101000	105470	282Book Gain/Loss on Land Sales	GPS	388	9	106	30	53	169	22	0	0
4101000	110200	IGC Tax Percentage Depletion Deduct	SE	0	0	0	0	0	0	0	0	0
4101000	110205	SRC Tax Percentage Depletion Deduct	SE	8	0	2	1	1	3	1	0	0
4101000	1102051	Tax Percentage Depletion - Deduction (Bl	SE	0	0	0	0	0	0	0	0	0
4101000	120105	Willow Wind Account Receivable	WA	0	0	0	0	0	0	0	0	0
4101000	205025	PMI-Fuel Cost Adjustment	SE	390	6	98	29	62	169	26	0	0
4101000	205200	M&S INVENTORY WRITE-OFF	SNPD	381	14	102	23	39	183	19	0	0
4101000	205205	Inventory Reserve - PMI	SE	32	0	8	2	5	14	2	0	0
4101000	205411	190PMISec263A	SE	-1,294	-19	-325	-97	-207	-561	-85	0	0
4101000	210100	283OR PUC Prepaid Taxes	OR	-38	0	-38	0	0	0	0	0	0
4101000	210120	283UT PUC Prepaid Taxes	UT	-17	0	0	0	0	-17	0	0	0
4101000	210130	283ID PUC Prepaid Taxes	IDU	10	0	0	0	0	0	10	0	0
4101000	210140	283WY PSC Prepaid Taxes	WYP	0	0	0	0	0	0	0	0	0

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4101000	210180	283Prepaid Membership Fees-EEI WSCC	SO	-202	-5	-55	-16	-27	-88	-12	0	0
4101000	210185	Prepaid Aircraft Maintenance Costs	SG	3	0	1	0	0	1	0	0	0
4101000	210190	Prepaid Water Rights	SG	0	0	0	0	0	0	0	0	0
4101000	210195	Prepaid Surety Bond Costs	SO	0	0	0	0	0	0	0	0	0
4101000	287396	Regulatory Liabilities - Interim Provisi	OTHER	0	0	0	0	0	0	0	0	0
4101000	287616	Regulatory Assets - Interim Provisions	OTHER	0	0	0	0	0	0	0	0	0
4101000	320210	190R&E Expense Sec174 Deduction	SO	0	0	0	0	0	0	0	0	0
4101000	320271	Contra Reg Asset - Pension Plan CTG	SO	403	9	110	31	55	175	23	0	0
4101000	320279	Reg Liability - FAS 158 Post Retirement	SO	-2,698	-60	-734	-208	-367	-1,173	-155	-1	0
4101000	320285	Reg Asset-Post Employment Costs	SO	-105	-2	-29	-8	-14	-46	-6	0	0
4101000	320290	LT Prepaid IBEW 57 Pension Contribution	OTHER	0	0	0	0	0	0	0	0	0
4101000	320291	Prepaid IBEw 57 Pension Contribution - C	OTHER	0	0	0	0	0	0	0	0	0
4101000	415110	190DEF REG ASSET-TRANSM SVC DEPOSIT	SG	-374	-6	-97	-29	-55	-164	-22	0	0
4101000	415120	190DEF REG ASSET-FOOTE CREEK CONTRACT	SG	0	0	0	0	0	0	0	0	0
4101000	415200	REG ASSET - OR TRANSPORTATION ELECTRIFIC	OTHER	96	0	0	0	0	0	0	0	96
4101000	415300	283Hazardous Waste/Environmental Cleanup	SO	461	10	125	35	63	201	26	0	0
4101000	415406	Reg Asset Utah ECAM	OTHER	0	0	0	0	0	0	0	0	0
4101000	415410	Reg Asset - Energy West Mining	SE	-247	-4	-62	-19	-39	-107	-16	0	0
4101000	415411	ContraRA DeerCreekAband CA	CA	4	4	0	0	0	0	0	0	0
4101000	415412	ContraRA DeerCreekAband ID	IDU	-102	0	0	0	0	0	-102	0	0
4101000	415413	ContraRA DeerCreekAband OR	OR	-398	0	-398	0	0	0	0	0	0
4101000	415414	ContraRA DeerCreekAband UT	UT	-2	0	0	0	0	-2	0	0	0
4101000	415415	ContraRA DeerCreekAband WA	WA	19	0	0	19	0	0	0	0	0
4101000	415416	ContraRA DeerCreekAband WY	WYU	0	0	0	0	0	0	0	0	0
4101000	415417	Contra RA UMWA Pension CA	OTHER	2	0	0	0	0	0	0	0	2
4101000	415418	Contra RA UMWA Pension ID	OTHER	0	0	0	0	0	0	0	0	0
4101000	415419	Contra RA UMWA Pension OR	OTHER	0	0	0	0	0	0	0	0	0
4101000	415420	Contra RA UMWA Pension UT	OTHER	0	0	0	0	0	0	0	0	0
4101000	415421	Contra RA UMWA Pension WA	OTHER	8	0	0	0	0	0	0	0	8
4101000	415422	Contra RA UMWA Pension WY	OTHER	0	0	0	0	0	0	0	0	0
4101000	415431	Reg Asset - WA Transportation Electrific	OTHER	10	0	0	0	0	0	0	0	10
4101000	415501	Cholla Plt Transact Costs- APS Amort - I	IDU	0	0	0	0	0	0	0	0	0
4101000	415502	Cholla Plt Transact Costs- APS Amort - O	OR	0	0	0	0	0	0	0	0	0

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4101000	415530	Reg Asset - ID 2017 Protocol - MSP Defer	IDU	37	0	0	0	0	0	37	0	0
4101000	415531	Reg Asset - UT 2017 Protocol - MSP Defer	UT	1,082	0	0	0	0	1,082	0	0	0
4101000	415532	Reg Asset - WY 2017 Protocol - MSP Defer	WYP	393	0	0	0	393	0	0	0	0
4101000	415545	Reg Asset - WA Merwin Project	OTHER	0	0	0	0	0	0	0	0	0
4101000	415585	Reg Asset - OR Sch 203 - Black Cap	OTHER	0	0	0	0	0	0	0	0	0
4101000	415655	CA GHG Allowance	OTHER	0	0	0	0	0	0	0	0	0
4101000	415675	Reg Asset - UT - Deferred Stock Redempti	OTHER	-20	0	0	0	0	0	0	0	-20
4101000	415676	Reg Asset - WY - Deferred Stock Redempti	OTHER	-7	0	0	0	0	0	0	0	-7
4101000	415677	Reg Asset - Pref Stock Redemp Loss WA	OTHER	-3	0	0	0	0	0	0	0	-3
4101000	415680	190Def Intervenor Funding Grants-OR	OTHER	109	0	0	0	0	0	0	0	109
4101000	415700	190Reg Liabs BPA balancing accounts-OR	OTHER	0	0	0	0	0	0	0	0	0
4101000	415701	CA Deferred Intervenor Funding	OTHER	0	0	0	0	0	0	0	0	0
4101000	415720	Reg Asset - Community Solar - OR	OTHER	39	0	0	0	0	0	0	0	39
4101000	415815	Insurance Reserve	SO	-56	-1	-15	-4	-8	-24	-3	0	0
4101000	415820	Contra Pension Reg Asset MMT & CTG OR	OR	124	0	124	0	0	0	0	0	0
4101000	415821	Contra Pension Reg Asset MMT & CTG WY	WYP	0	0	0	0	0	0	0	0	0
4101000	415823	Contra Pension Reg Asset CTG - UT	UT	0	0	0	0	0	0	0	0	0
4101000	415824	Contra Pension Reg Asset MMT & CTG CA	CA	11	11	0	0	0	0	0	0	0
4101000	415825	Contra Pension Reg Asset CTG - WA	WA	0	0	0	0	0	0	0	0	0
4101000	415845	Reg Asset - OR Sch 94 Distribution Safet	OTHER	0	0	0	0	0	0	0	0	0
4101000	415850	Unrecovered Plant Powerdale	SG	0	0	0	0	0	0	0	0	0
4101000	415851	Powerdale Hydro Decom Reg Asset - CA	CA	0	0	0	0	0	0	0	0	0
4101000	415862	Reg Asset - CA Mobile Home Park Conversi	OTHER	2	0	0	0	0	0	0	0	2
4101000	415863	Reg Asset - UT Subscriber Solar Program	UT	26	0	0	0	0	26	0	0	0
4101000	415866	Reg Asset - OR Solar Feed-in Tariff	OTHER	-17	0	0	0	0	0	0	0	-17
4101000	415869	Reg Asset - CA Deferred Net Power Costs	OTHER	0	0	0	0	0	0	0	0	0
4101000	415870	Deferred Excess Net Power Costs CA	CA	483	483	0	0	0	0	0	0	0
4101000	415874	Deferred Excess Net Power Costs - WY 09	OTHER	1,796	0	0	0	0	0	0	0	1,796
4101000	415875	Deferred Excess Net Power Costs - UT	OTHER	8,090	0	0	0	0	0	0	0	8,090
4101000	415878	REG ASSET - UT LIQUIDATED DAMAGES NAUGHT	UT	-9	0	0	0	0	-9	0	0	0
4101000	415879	Reg Asset - WY Liquidation Damages N2	WYP	-1	0	0	0	-1	0	0	0	0
4101000	415882	Deferral of Renewable Energy Credit - WA	OTHER	-5	0	0	0	0	0	0	0	-5
4101000	415884	Reg Asset - Current Reclass - Other	OTHER	0	0	0	0	0	0	0	0	0

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4101000	415885	Reg Asset - Noncurrent Reclass - Other	OTHER	-4	0	0	0	0	0	0	0	-4
4101000	415886	Reg Asset - ID Deferred Excess Net Power	OTHER	0	0	0	0	0	0	0	0	0
4101000	415888	Reg Asset - UT Deferred Excess Net Power	OTHER	0	0	0	0	0	0	0	0	0
4101000	415892	Deferred Excess Net Power Costs - ID 09	OTHER	2,959	0	0	0	0	0	0	0	2,959
4101000	415894	Reg Asset - REC Sales Deferral - CA - No	OTHER	0	0	0	0	0	0	0	0	0
4101000	415900	OR SB 408 Recovery	OTHER	0	0	0	0	0	0	0	0	0
4101000	415901	Reg Asset - WY Deferred Excess Net Power	OTHER	0	0	0	0	0	0	0	0	0
4101000	415903	Reg Asset _ REC Sales Deferral - WA	OTHER	0	0	0	0	0	0	0	0	0
4101000	415904	Reg Asset - WY REC's in Rates - Current	OTHER	0	0	0	0	0	0	0	0	0
4101000	415905	Reg Asset - OR REC's in Rates - Current	OTHER	0	0	0	0	0	0	0	0	0
4101000	415906	Reg Asset - REC Sales Deferral - OR - No	OTHER	-44	0	0	0	0	0	0	0	-44
4101000	415907	Reg Asset - CA Solar Feed-in Tariff - Cu	OTHER	0	0	0	0	0	0	0	0	0
4101000	415908	Reg Asset - OR Solar Feed-In Tariff - Cu	OTHER	0	0	0	0	0	0	0	0	0
4101000	415910	Reg Asset - Naughton Unit #3 Costs	OTHER	0	0	0	0	0	0	0	0	0
4101000	415917	Reg Asset - Naughton Unit #3 Costs - CA	OTHER	0	0	0	0	0	0	0	0	0
4101000	415918	Reg Asset - RPS Compliance Purchases	OTHER	0	0	0	0	0	0	0	0	0
4101000	415920	Reg Asset - Depreciation Increase - ID	IDU	18	0	0	0	0	0	18	0	0
4101000	415921	Reg Asset - Depreciation Increase - UT	UT	-31	0	0	0	0	-31	0	0	0
4101000	415922	Reg Asset - Depreciation Increase - WY	WYP	-109	0	0	0	-109	0	0	0	0
4101000	415923	Reg Asset - Carbon Unrecovered Plant - I	IDU	-118	0	0	0	0	0	-118	0	0
4101000	415924	Reg Asset - Carbon Unrecovered Plant - U	UT	-847	0	0	0	0	-847	0	0	0
4101000	415925	Reg Asset - Carbon Unrecovered Plant - W	WYP	-285	0	0	0	-285	0	0	0	0
4101000	415930	Reg Asset - Carbon Decommissioning - ID	IDU	0	0	0	0	0	0	0	0	0
4101000	415931	Reg Asset - Carbon Decommissioning - UT	UT	0	0	0	0	0	0	0	0	0
4101000	415932	Reg Asset - Carbon Decommissioning - WY	WYP	0	0	0	0	0	0	0	0	0
4101000	415933	Reg Liability - Contra - Carbon Decommis	IDU	-9	0	0	0	0	0	-9	0	0
4101000	415934	Reg Liability - Contra - Carbon Decommis	UT	-62	0	0	0	0	-62	0	0	0
4101000	415935	Reg Liability - Contra - Carbon Decommis	WYP	-153	0	0	0	-153	0	0	0	0
4101000	415936	REG ASSET - CARBON PLANT DECOMMISSIONING	SG	0	0	0	0	0	0	0	0	0
4101000	425100	190Deferred Regulatory Expense-IDU	IDU	10	0	0	0	0	0	10	0	0
4101000	425102	Reg Asset - CA GreenHouse Gas Allowance	OTHER	0	0	0	0	0	0	0	0	0
4101000	425103	Reg Asset - Other Regulatory Assets - Cu	OTHER	0	0	0	0	0	0	0	0	0
4101000	425104	Reg Asset - OR Asset Sale Gain Giveback	OTHER	0	0	0	0	0	0	0	0	0

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4101000	425215	283Unearned Joint Use Pole Contact Revnu	SNPD	-5	0	-1	0	-1	-3	0	0	0
4101000	425225	Duke/Hermiston Contract Renegotiation	SG	0	0	0	0	0	0	0	0	0
4101000	425295	BPA Conservation Rate Credit	SG	0	0	0	0	0	0	0	0	0
4101000	425400	UT Kalamath Relicensing Costs	OTHER	-886	0	0	0	0	0	0	0	-886
4101000	430110	Reg Asset Balance Reclass	OTHER	5,691	0	0	0	0	0	0	0	5,691
4101000	430111	Reg Assets - SB 1149 Balance Reclass	OTHER	0	0	0	0	0	0	0	0	0
4101000	430112	Reg Asset - Other - Balance Reclass	OTHER	244	0	0	0	0	0	0	0	244
4101000	430113	Reg Asset - Def NPC Balance Reclass	OTHER	0	0	0	0	0	0	0	0	0
4101000	505510	190PMI Vacation/Bonus	SE	3	0	1	0	0	1	0	0	0
4101000	505600	190Vacation Sickleave & PT Accrual	SO	0	0	0	0	0	0	0	0	0
4101000	605101	Trojan Decommissioning Costs - WA	WA	0	0	0	0	0	0	0	0	0
4101000	605102	Trojan Decommissioning Costs - OR	OR	0	0	0	0	0	0	0	0	0
4101000	605103	ARO/Reg Diff - Trojan - WA	WA	-1	0	0	-1	0	0	0	0	0
4101000	610100	283PMI AMORT DEVELOPMENT	SE	-93	-1	-23	-7	-15	-40	-6	0	0
4101000	6101001	190NOPA 103-99-00 RAR	SO	10	0	3	1	1	4	1	0	0
4101000	610111	283PMI SALE OF ASSETS	SE	32	0	8	2	5	14	2	0	0
4101000	610114	PMI EITF Pre stripping Cost	SE	-811	-12	-204	-61	-130	-352	-53	0	0
4101000	610142	283Reg Liability-UT Home Energy Lifeline	UT	22	0	0	0	0	22	0	0	0
4101000	610143	283Reg Liability-WA Low Energy Program	WA	0	0	0	0	0	0	0	0	0
4101000	610146	190OR Reg Asset/Liability Consol	OR	0	0	0	0	0	0	0	0	0
4101000	705200	190OR Gain on Sale of Halsey-OR	OTHER	0	0	0	0	0	0	0	0	0
4101000	705210	190Property Insurance	SO	0	0	0	0	0	0	0	0	0
4101000	705261	Reg Liability - Sale of Renewable Energy	OTHER	0	0	0	0	0	0	0	0	0
4101000	705265	Reg Liab - OR Energy Conservation Charge	OTHER	-32	0	0	0	0	0	0	0	-32
4101000	705300	Reg. Liability - Deferred Benefit_Arch S	SE	0	0	0	0	0	0	0	0	0
4101000	705305	Reg Liability-CA Gain on Sale of Asset	CA	0	0	0	0	0	0	0	0	0
4101000	705337	Reg Liability - Sale of Renewable Energy	OTHER	-21	0	0	0	0	0	0	0	-21
4101000	705454	Reg Liability - UT Property Insurance Re	UT	-297	0	0	0	0	-297	0	0	0
4101000	705534	Regulatory Liability - OR Asset Sale Gai	OTHER	0	0	0	0	0	0	0	0	0
4101000	705537	Regulatory Liability - Other Reg Liabili	OTHER	0	0	0	0	0	0	0	0	0
4101000	705700	Reg Liability - Current Reclass - Other	OTHER	0	0	0	0	0	0	0	0	0
4101000	705755	Reg Liability - Non current Reclass - Ot	OTHER	4	0	0	0	0	0	0	0	4
4101000	715800	190Redding Contract	SG	0	0	0	0	0	0	0	0	0

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4101000	720200	190Deferred Compensation Payout	SO	-17	0	-5	-1	-2	-7	-1	0	0
4101000	720300	190Pension/Retirement (Accrued/Prepaid)	SO	0	0	0	0	0	0	0	0	0
4101000	720500	190Severance	SO	63	1	17	5	9	28	4	0	0
4101000	720800	190FAS 158 Pension Liability	SO	6,872	153	1,870	529	934	2,989	394	1	0
4101000	720805	FAS 158 - Funded Pension Asset	SO	0	0	0	0	0	0	0	0	0
4101000	720810	190FAS 158 Post Retirement Liability	SO	2,365	53	644	182	322	1,029	136	0	0
4101000	720815	FAS 158 Post Retirement Liability	SO	-414	-9	-113	-32	-56	-180	-24	0	0
4101000	910530	190Injuries & Damages	SO	-2,536	-57	-690	-195	-345	-1,103	-146	-1	0
4101000	910560	283SMUD Revenue Imputation-UT Reg Liab	OTHER	0	0	0	0	0	0	0	0	0
4101000 Total				**239,620**	**4,756**	**58,105**	**14,379**	**30,519**	**98,660**	**12,582**	**50**	**18,013**
4111000	100105	283FAS 109 Def Tax Liab WA-NUTIL	OTHER	389	0	0	0	0	0	0	0	389
4111000	105100	190CAPITALIZED LABOR COSTS	SO	-489	-11	-133	-38	-66	-213	-28	0	0
4111000	105107	Non-Protected PP&E EDIT - ID	IDU	-357	0	0	0	0	0	-357	0	0
4111000	105112	Non-Protected PP&E EDIT - UT	UT	-104,732	0	0	0	0	-104,732	0	0	0
4111000	1051151	Depreciation Flow-Through - CA	CA	-777	-777	0	0	0	0	0	0	0
4111000	1051152	Depreciation Flow-Through - FERC	FERC	-251	0	0	0	0	0	0	-251	0
4111000	1051153	Depreciation Flow-Through - ID	IDU	-1,626	0	0	0	0	0	-1,626	0	0
4111000	1051154	Depreciation Flow-Through - OR	OR	-8,701	0	-8,701	0	0	0	0	0	0
4111000	1051155	Depreciation Flow-Through - OTHER	OTHER	-67	0	0	0	0	0	0	0	-67
4111000	1051156	Depreciation Flow-Through - UT	UT	-12,111	0	0	0	0	-12,111	0	0	0
4111000	1051157	Depreciation Flow-Through - WA	WA	-900	0	0	-900	0	0	0	0	0
4111000	1051158	Depreciation Flow-Through - WYP	WYP	-3,753	0	0	0	-3,753	0	0	0	0
4111000	1051159	Depreciation Flow-Through - WYU	WYU	-923	0	0	0	-923	0	0	0	0
4111000	105120	Book Depreciation	SCHMDEXP	-241,934	-4,877	-64,659	-18,879	-33,988	-105,531	-13,945	-56	0
4111000	105121	282DIT PMIDepreciation-Book	SE	-4,087	-59	-1,026	-307	-653	-1,772	-268	-1	0
4111000	105123	Sec 481a Adj- Repair Deduction	SG	0	0	0	0	0	0	0	0	0
4111000	105130	CIAC	CIAC	-25,325	-918	-6,776	-1,557	-2,592	-12,189	-1,293	0	0
4111000	105140	Highway Relocation	SNPD	-516	-19	-138	-32	-53	-248	-26	0	0
4111000	105142	Avoided Costs	SNP	-10,145	-212	-2,667	-751	-1,377	-4,551	-583	-2	-2
4111000	105146	Capitalization of Test Energy	SG	0	0	0	0	0	0	0	0	0
4111000	105220	282CHOLLA TAX LEASE	SG	-345	-5	-90	-27	-50	-152	-20	0	0
4111000	105471	UT Kalamath Relicensing Costs	OTHER	0	0	0	0	0	0	0	0	0
4111000	110100	283BOOK COST DEPLETION ADDBACK	SE	0	0	0	0	0	0	0	0	0

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Deferred Income Tax Expense
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Accou	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4111000	205100	190COAL PILE INVENTORY	SE	-61	-1	-15	-5	-10	-26	-4	0	0
4111000	205210	ERC (Emission Reduction Credit) Impairme	SE	0	0	0	0	0	0	0	0	0
4111000	210200	283Prepaid Taxes-Property Taxes	GPS	145	3	40	11	20	63	8	0	0
4111000	220100	190Bad Debt Allowance	BADDEBT	-98	-5	-35	-12	-7	-33	-5	0	0
4111000	2874941	190Idaho ITC Credits	SO	0	0	0	0	0	0	0	0	0
4111000	320270	Reg Asset FAS 158 Pension Liab	SO	-8,943	-200	-2,434	-688	-1,216	-3,890	-513	-2	0
4111000	320280	Reg Asset FAS 158 Post Retire Liab	SO	3,453	77	940	266	470	1,502	198	1	0
4111000	320281	Reg Asset - Post-Retirement Settlement L	SO	-87	-2	-24	-7	-12	-38	-5	0	0
4111000	320282	Reg Asset - Post-Retirement Settlement L	UT	72	0	0	0	0	72	0	0	0
4111000	320283	Reg Asset - Post-Retirement Settlement L	WYU	-5	0	0	0	-5	0	0	0	0
4111000	415115	Reg Asset - UT STEP Pilot Programs Balan	OTHER	-2,181	0	0	0	0	0	0	0	-2,181
4111000	415301	190Hazardous Waste/Environmental-WA	WA	-26	0	0	-26	0	0	0	0	0
4111000	415406	Reg Asset Utah ECAM	OTHER	0	0	0	0	0	0	0	0	0
4111000	415423	Contra PP&E Deer Creek	SE	0	0	0	0	0	0	0	0	0
4111000	415424	Contra Reg Asset - Deer Creek Abandonmen	SE	-3,878	-56	-973	-292	-620	-1,681	-254	-1	0
4111000	415425	Contra Reg Asset - UMWA Pension	OTHER	-112	0	0	0	0	0	0	0	-112
4111000	415430	Reg Asset - CA - Transportation Electri	OTHER	-109	0	0	0	0	0	0	0	-109
4111000	415500	283Cholla Plt Trans-APS Amort	SGCT	0	0	0	0	0	0	0	0	0
4111000	415510	283WA DISALLOWED COLSTRIP #3 WRITE-OFF	WA	-13	0	0	-13	0	0	0	0	0
4111000	415702	REG ASSET - LAKE SIDE LIQ - WY	WYP	-7	0	0	0	-7	0	0	0	0
4111000	415703	Goodnoe Hills Liquidation Damages - WY	WYP	-5	0	0	0	-5	0	0	0	0
4111000	415704	Reg Liability - Tax Revenue Adjustment -	UT	0	0	0	0	0	0	0	0	0
4111000	415705	Reg Liability - Tax Revenue Adjustment -	WYP	0	0	0	0	0	0	0	0	0
4111000	415710	Reg Liability - WA - Accelerated Depreci	WA	-3,101	0	0	-3,101	0	0	0	0	0
4111000	415803	RTO Grid West N/R Writeoff WA	WA	0	0	0	0	0	0	0	0	0
4111000	415804	RTO Grid West Notes Receivable-OR	OR	0	0	0	0	0	0	0	0	0
4111000	415806	RTO Grid West N/R Writeoff ID	IDU	0	0	0	0	0	0	0	0	0
4111000	415822	Reg Asset _ Pension MMT -UT	UT	0	0	0	0	0	0	0	0	0
4111000	415827	Reg Asset Post Retirement MMT - OR	OR	-24	0	-24	0	0	0	0	0	0
4111000	415828	Reg Asset Post Retirement MMT - WY	WYP	0	0	0	0	0	0	0	0	0
4111000	415829	Reg Asset - Post - Ret MMT -UT	UT	0	0	0	0	0	0	0	0	0
4111000	415831	Reg Asset Post Retirement MMT - CA	CA	-2	-2	0	0	0	0	0	0	0
4111000	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	0	0	0	0	0	0	0	0	0

Deferred Income Tax Expense

Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Accou	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4111000	415852	Powerdale Decommissioning Reg Asset - ID	IDU	-6	0	0	0	0	0	-6	0	0
4111000	415853	Powerdale Decommissioning Reg Asset - OR	OR	0	0	0	0	0	0	0	0	0
4111000	415854	Powerdale Decommissioning Reg Asset - WA	WA	0	0	0	0	0	0	0	0	0
4111000	415855	CA - January 2010 Storm Costs	OTHER	-361	0	0	0	0	0	0	0	-361
4111000	415856	Powerdale Decommissioning Reg Asset - WY	WYP	0	0	0	0	0	0	0	0	0
4111000	415857	ID - Deferred Overburden Costs	OTHER	-26	0	0	0	0	0	0	0	-26
4111000	415858	WY - Deferred Overburden Costs	WYP	-72	0	0	0	-72	0	0	0	0
4111000	415859	WY - Deferred Advertising Costs	WYP	0	0	0	0	0	0	0	0	0
4111000	415865	Reg Asset - UT MPA	OTHER	0	0	0	0	0	0	0	0	0
4111000	415867	Reg Asset - CA Solar Feed-in Tariff	OTHER	0	0	0	0	0	0	0	0	0
4111000	415868	Reg Asset - UT - Solar Incentive Program	OTHER	2,181	0	0	0	0	0	0	0	2,181
4111000	415876	Deferred Excess Net PowerCosts - OR	OTHER	715	0	0	0	0	0	0	0	715
4111000	415881	Deferral of Renewable Energy Credit - UT	OTHER	-50	0	0	0	0	0	0	0	-50
4111000	415883	Deferral of Renewable Energy Credit - WY	OTHER	-83	0	0	0	0	0	0	0	-83
4111000	415890	ID MEHC 2006 Transition Costs	IDU	0	0	0	0	0	0	0	0	0
4111000	415891	WY - 2006 Transition Severance Costs	WYP	0	0	0	0	0	0	0	0	0
4111000	415893	OR - MEHC Transition Service Costs	OTHER	0	0	0	0	0	0	0	0	0
4111000	415895	OR_RCAC SEP-DEC 07 DEFERRED	OR	0	0	0	0	0	0	0	0	0
4111000	415896	WA - Chehalis Plant Revenue Requirement	WA	0	0	0	0	0	0	0	0	0
4111000	415897	Reg Asset MEHC Transition Service Costs	CA	0	0	0	0	0	0	0	0	0
4111000	415898	Deferred Coal Costs - Naughton Contract	SE	0	0	0	0	0	0	0	0	0
4111000	415902	Reg Asset - UT REC's in Rates - Current	OTHER	0	0	0	0	0	0	0	0	0
4111000	415911	Contra Reg Asset - Naughton Unit $3 - CA	CA	0	0	0	0	0	0	0	0	0
4111000	415912	Contra Reg Asset - Naughton Unit #3 - OR	OTHER	0	0	0	0	0	0	0	0	0
4111000	415913	Contra Reg Asset - Naughton Unit #3 - WA	OTHER	0	0	0	0	0	0	0	0	0
4111000	415914	Reg Asset - UT - Naughton U3 Costs	UT	0	0	0	0	0	0	0	0	0
4111000	415915	Reg Asset - WY - Naughton U3 Costs	WYP	0	0	0	0	0	0	0	0	0
4111000	415926	Reg Liability - Depreciation Decrease -	OTHER	-309	0	0	0	0	0	0	0	-309
4111000	415927	Reg Liability - Depreciation Decrease De	WA	0	0	0	0	0	0	0	0	0
4111000	415938	Reg Asset - Carbon Plant Decommissioning	CA	0	0	0	0	0	0	0	0	0
4111000	425105	Reg Asset - OR Asset Sale Gain Giveback	OTHER	-35	0	0	0	0	0	0	0	-35
4111000	425125	Deferred Coal Cost - Arch	SE	0	0	0	0	0	0	0	0	0
4111000	425215	283Unearned Joint Use Pole Contact Revnu	SNPD	0	0	0	0	0	0	0	0	0

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Deferred Income Tax Expense
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Accou	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4111000	425250	283TGS BUYOUT-SG	SG	-4	0	-1	0	-1	-2	0	0	0
4111000	425280	283JOSEPH SETTLEMENT-SG	SG	0	0	0	0	0	0	0	0	0
4111000	425360	190Hermiston Swap	SG	-42	-1	-11	-3	-6	-19	-2	0	0
4111000	425380	190Idaho Customer Bal Acct	OTHER	0	0	0	0	0	0	0	0	0
4111000	430100	283Weatherization	OTHER	-2,385	0	0	0	0	0	0	0	-2,385
4111000	430117	Reg Asset - Current DSM	OTHER	0	0	0	0	0	0	0	0	0
4111000	505115	283Sales & Use Tax Audit	SO	0	0	0	0	0	0	0	0	0
4111000	505125	190Accrued Royalties	SE	-283	-4	-71	-21	-45	-123	-19	0	0
4111000	505400	190Bonus Liability	SO	51	1	14	4	7	22	3	0	0
4111000	505600	190Vacation Sickleave & PT Accrual	SO	-115	-3	-31	-9	-16	-50	-7	0	0
4111000	505601	Sick Leave Accrual - PMI	SE	0	0	0	0	0	0	0	0	0
4111000	505700	190Accrued Retention Bonus	SO	146	3	40	11	20	64	8	0	0
4111000	605100	283TROJAN DECOMMISSIONING AMORT	TROJD	13	0	3	1	2	5	1	0	0
4111000	605301	Environmental Liability - Regulated	SO	-110	-2	-30	-8	-15	-48	-6	0	0
4111000	605710	REVERSE ACCRUED FINAL RECLAMATION	OTHER	1,128	0	0	0	0	0	0	0	1,128
4111000	605715	Trapper Mine Contract Obligation	SE	-69	-1	-17	-5	-11	-30	-5	0	0
4111000	610000	283PMI Development Costs	SE	21	0	5	2	3	9	1	0	0
4111000	610143	283Reg Liability-WA Low Energy Program	WA	317	0	0	317	0	0	0	0	0
4111000	610144	Reg Liability - CA California Alternativ	OTHER	0	0	0	0	0	0	0	0	0
4111000	610145	190REG LIAB_DSM	OTHER	-5,691	0	0	0	0	0	0	0	-5,691
4111000	610148	Reg Liability - Def NPC Balance Reclass	OTHER	0	0	0	0	0	0	0	0	0
4111000	705240	283CA Alternative Rate for Energy Progra	OTHER	-62	0	0	0	0	0	0	0	-62
4111000	705241	Reg Liability - CA California Alternativ	OTHER	0	0	0	0	0	0	0	0	0
4111000	705245	REG LIABILITY - OR DIRECT ACCESS 5 YEAR	OTHER	-459	0	0	0	0	0	0	0	-459
4111000	705262	Reg Liability - Sale of REC's-ID	OTHER	0	0	0	0	0	0	0	0	0
4111000	705263	Reg Liability - Sale of REC's-WA	OTHER	0	0	0	0	0	0	0	0	0
4111000	705266	Reg Liability - Energy Savings Assistanc	OTHER	-13	0	0	0	0	0	0	0	-13
4111000	705267	Reg Liability - WA Decoupling Mechanism	OTHER	111	0	0	0	0	0	0	0	111
4111000	705281	Non-Property EDIT - ID	IDU	-43	0	0	0	0	0	-43	0	0
4111000	705283	Non-Property EDIT - UT	UT	-22,561	0	0	0	0	-22,561	0	0	0
4111000	705301	Reg Liability - OR 2010 Protocol Def	OR	0	0	0	0	0	0	0	0	0
4111000	705336	Reg Liability - Sale of Renewable Energy	OTHER	-74	0	0	0	0	0	0	0	-74
4111000	705340	Reg Liability - Excess Income Tax Deferr	OTHER	-671	0	0	0	0	0	0	0	-671

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Deferred Income Tax Expense
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Accou	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4111000	705341	Reg Liability - Excess Income Tax Deferr	OTHER	255	0	0	0	0	0	0	0	255
4111000	705342	Reg Liability - Excess Income Tax Deferr	OTHER	-5,470	0	0	0	0	0	0	0	-5,470
4111000	705343	Reg Liability - Excess Income Tax Deferr	OTHER	7,240	0	0	0	0	0	0	0	7,240
4111000	705344	Reg Liability - Excess Income Tax Deferr	OTHER	-34	0	0	0	0	0	0	0	-34
4111000	705345	Reg Liability - Excess Income Tax Deferr	OTHER	2,375	0	0	0	0	0	0	0	2,375
4111000	705346	Deferral of Protected PP&E ARAM - CA	CA	659	659	0	0	0	0	0	0	0
4111000	705347	Deferral of Protected PP&E ARAM - ID	IDU	1,419	0	0	0	0	0	1,419	0	0
4111000	705348	Deferral of Protected PP&E ARAM - OR	OR	7,806	0	7,806	0	0	0	0	0	0
4111000	705349	Deferral of Protected PP&E ARAM - UT	UT	13,478	0	0	0	0	13,478	0	0	0
4111000	705350	Deferral of Protected PP&E ARAM - WA	WA	1,954	0	0	1,954	0	0	0	0	0
4111000	705351	Deferral of Protected PP&E ARAM - WY	WYU	4,300	0	0	0	4,300	0	0	0	0
4111000	705400	Reg Liability - OR Injuries & Damages Re	OR	5	0	5	0	0	0	0	0	0
4111000	705420	Reg Liability - CA GHG Allowance Revenue	OTHER	-282	0	0	0	0	0	0	0	-282
4111000	705451	Reg Liability - OR Property Insurance Re	OR	1,715	0	1,715	0	0	0	0	0	0
4111000	705453	Reg Liability - ID Property Insurance Re	IDU	-28	0	0	0	0	0	-28	0	0
4111000	705455	Reg Liability - WY Property Insurance Re	WYP	-86	0	0	0	-86	0	0	0	0
4111000	705500	Reg Liability - Powerdale Decommissionin	UT	0	0	0	0	0	0	0	0	0
4111000	705514	Regulatory Liability - OR Deferred Exces	OTHER	0	0	0	0	0	0	0	0	0
4111000	705515	Regulatory Liability - OR Deferred Exces	OTHER	-1,467	0	0	0	0	0	0	0	-1,467
4111000	705517	Regulatory Liability - UT Deferred Exces	OTHER	0	0	0	0	0	0	0	0	0
4111000	705518	Regulatory Liability - WA Deferred Exces	OTHER	0	0	0	0	0	0	0	0	0
4111000	705519	Regulatory Liability - WA Deferred Exces	OTHER	2,262	0	0	0	0	0	0	0	2,262
4111000	705521	Regulatory Liability - WY Deferred Exces	OTHER	2,183	0	0	0	0	0	0	0	2,183
4111000	705522	Regulatory Liability - UT RECS in Rates	OTHER	0	0	0	0	0	0	0	0	0
4111000	705523	Regulatory Liability - WA RECS in Rates	OTHER	0	0	0	0	0	0	0	0	0
4111000	705525	REGULATORY LIABILITY - SALE OF REC - OR	OTHER	0	0	0	0	0	0	0	0	0
4111000	705526	Regulatory Liability - CA Solar Feed-in	OTHER	0	0	0	0	0	0	0	0	0
4111000	705527	Regulatory Liability - CA Solar Feed-in	OTHER	110	0	0	0	0	0	0	0	110
4111000	705530	Regulatory Liability - UT Solar Feed-in	OTHER	0	0	0	0	0	0	0	0	0
4111000	705531	Regulatory Liability - UT Solar Feed-in	OTHER	-793	0	0	0	0	0	0	0	-793
4111000	705536	Regulatory Liability - CA GreenHouse Gas	OTHER	0	0	0	0	0	0	0	0	0
4111000	705600	RegLiability - OR 2012 GRC Giveback	OTHER	0	0	0	0	0	0	0	0	0
4111000	705700	Reg Liability - Current Reclass - Other	OTHER	0	0	0	0	0	0	0	0	0

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Deferred Income Tax Expense

Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Accou	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4111000	715105	MCI FOG Wire Lease	SG	115	2	30	9	17	50	7	0	0
4111000	715720	190NW Power Act(BPA Regional Crs)-WA	OTHER	111	0	0	0	0	0	0	0	111
4111000	715810	Chehalis WA EFSEC C02 Mitigation Obligat	SG	31	0	8	2	4	14	2	0	0
4111000	720300	190Pension/Retirement (Accrued/Prepaid)	SO	35	1	10	3	5	15	2	0	0
4111000	720560	Pension Liability - UMWA Withdrawal Obli	SE	0	0	0	0	0	0	0	0	0
4111000	740100	283Post Merger Debt Loss	SNP	-144	-3	-38	-11	-20	-65	-8	0	0
4111000	910245	Contra Receivable from Joint Owners	SO	63	1	17	5	9	28	4	0	0
4111000	910905	283PMI BCC Underground Mine Cost Deplet	SE	-231	-3	-58	-17	-37	-100	-15	0	0
4111000	920110	190PMIWYExtractionTax	SE	-79	-1	-20	-6	-13	-34	-5	0	0
4111000	930100	190OR BETC Credit	OTHER	0	0	0	0	0	0	0	0	0
4111000	9301001	190OR BETC Credit	SG	0	0	0	0	0	0	0	0	0
4111000	999998	Deferred Income Tax Expense ~ Solar ITC	SG	1	0	0	0	0	1	0	0	0
4111000 Total				**-422,965**	**-6,414**	**-77,340**	**-24,129**	**-40,801**	**-254,875**	**-17,419**	**-312**	**-1,674**
Grand Total				**-183,345**	**-1,658**	**-19,235**	**-9,750**	**-10,283**	**-156,215**	**-4,837**	**-262**	**16,339**

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Investment Tax Credit Amortization
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4114000	DEF ITC-EL-FED-CR	0	DEF ITC CREDIT FED	DGU	-2,944	0	0	0	-157	-2,456	-329	-2	0
4114000 Total					**-2,944**	**0**	**0**	**0**	**-157**	**-2,456**	**-329**	**-2**	**0**
Grand Total					**-2,944**	**0**	**0**	**0**	**-157**	**-2,456**	**-329**	**-2**	**0**

Exhibit PAC/1302
McCoy/351

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Electric Plant In Service with Unclassified
Balances as of June 2019
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	0	0	0	0	0	1,000	0	0
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG	10,338	159	2,690	816	1,512	4,548	610	3	0
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG-P	175,245	2,693	45,603	13,830	25,630	77,103	10,335	50	0
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG-U	9,951	153	2,590	785	1,455	4,378	587	3	0
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	UT	-32,081	0	0	0	0	-32,081	0	0	0
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	OR	531	0	531	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	SG	40,389	621	10,510	3,188	5,907	17,770	2,382	11	0
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	UT	1,579	0	0	0	0	1,579	0	0	0
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	WYP	4,189	0	0	0	4,189	0	0	0	0
1010000	ELEC PLANT IN SERV	3031050	RCMS - REGION CONSTRUCTION MGMT SYSTEM	SO	11,051	247	3,007	851	1,503	4,807	634	2	0
1010000	ELEC PLANT IN SERV	3031080	FUEL MANAGEMENT SYSTEM	SO	3,293	73	896	253	448	1,432	189	1	0
1010000	ELEC PLANT IN SERV	3031230	AUTOMATE POLE CARD SYSTEM	SO	4,410	98	1,200	339	600	1,918	253	1	0
1010000	ELEC PLANT IN SERV	3031680	DISTRIBUTION AUTOMATION PILOT PROJECT	SO	13,886	310	3,779	1,069	1,888	6,040	797	3	0
1010000	ELEC PLANT IN SERV	3031760	RECORD CENTER MANAGEMENT SOFTWARE	SO	291	6	79	22	40	127	17	0	0
1010000	ELEC PLANT IN SERV	3031830	CUSTOMER SERVICE SYSTEM (CSS)	CN	130,603	3,130	40,771	9,059	9,694	62,462	5,488	0	0
1010000	ELEC PLANT IN SERV	3032040	S A P	SO	179,271	4,001	48,789	13,801	24,375	77,980	10,288	36	0
1010000	ELEC PLANT IN SERV	3032220	ENTERPRISE DATA WRHSE - BI RPTG TOOL	SO	1,660	37	452	128	226	722	95	0	0
1010000	ELEC PLANT IN SERV	3032270	ENTERPRISE DATA WAREHOUSE	SO	5,877	131	1,599	452	799	2,556	337	1	0
1010000	ELEC PLANT IN SERV	3032330	FIELDNET PRO METER READING SYST -HRP REP	SO	2,908	65	791	224	395	1,265	167	1	0
1010000	ELEC PLANT IN SERV	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	2,020	45	550	156	275	879	116	0	0
1010000	ELEC PLANT IN SERV	3032360	2002 GRID NET POWER COST MODELING	SO	8,960	200	2,438	690	1,218	3,897	514	2	0
1010000	ELEC PLANT IN SERV	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	10,561	236	2,874	813	1,436	4,594	606	2	0
1010000	ELEC PLANT IN SERV	3032510	OPERATIONS MAPPING SYSTEM	SO	10,386	232	2,827	800	1,412	4,518	596	2	0
1010000	ELEC PLANT IN SERV	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	1,892	42	515	146	257	823	109	0	0
1010000	ELEC PLANT IN SERV	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	2,416	54	657	186	328	1,051	139	0	0
1010000	ELEC PLANT IN SERV	3032600	SINGLE PERSON SCHEDULING	SO	12,958	289	3,527	998	1,762	5,637	744	3	0
1010000	ELEC PLANT IN SERV	3032640	TIBCO SOFTWARE	SO	6,357	142	1,730	489	864	2,765	365	1	0
1010000	ELEC PLANT IN SERV	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	1,600	25	416	126	234	704	94	0	0
1010000	ELEC PLANT IN SERV	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	207	3	54	16	30	91	12	0	0
1010000	ELEC PLANT IN SERV	3032740	GADSBY INTANGIBLE ASSETS	SG	51	1	13	4	7	22	3	0	0
1010000	ELEC PLANT IN SERV	3032760	SWIFT 2 IMPROVEMENTS	SG	23,200	357	6,037	1,831	3,393	10,208	1,368	7	0
1010000	ELEC PLANT IN SERV	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	652	10	170	51	95	287	38	0	0
1010000	ELEC PLANT IN SERV	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	117	2	31	9	17	52	7	0	0
1010000	ELEC PLANT IN SERV	3032830	VCPRO - XEROX CUST STMT FRMTR ENHANCE -	SO	2,629	59	716	202	357	1,144	151	1	0
1010000	ELEC PLANT IN SERV	3032860	WEB SOFTWARE	SO	2,680	60	729	206	364	1,166	154	1	0
1010000	ELEC PLANT IN SERV	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	8,774	135	2,283	692	1,283	3,860	517	2	0
1010000	ELEC PLANT IN SERV	3032910	WYOMING VHF (VPC) SPECTRUM	WYP	1,039	0	0	0	1,039	0	0	0	0
1010000	ELEC PLANT IN SERV	3032920	IDAHO VHF (VPC) SPECTRUM	IDU	3,357	0	0	0	0	0	3,357	0	0
1010000	ELEC PLANT IN SERV	3032930	UTAH VHF (VPC) SPECTRUM	UT	4,287	0	0	0	0	4,287	0	0	0
1010000	ELEC PLANT IN SERV	3032990	P8DM - FILENET P8	SO	6,292	140	1,712	484	855	2,737	361	1	0
1010000	ELEC PLANT IN SERV	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	71,794	1,103	18,683	5,666	10,500	31,588	4,234	20	0
1010000	ELEC PLANT IN SERV	3033170	GTX VERSION 7 SOFTWARE	CN	7,579	182	2,366	526	563	3,625	318	0	0
1010000	ELEC PLANT IN SERV	3033190	ITRON METER READING SOFTWARE	CN	5,868	141	1,832	407	436	2,807	247	0	0

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1010000	ELEC PLANT IN SERV	3033210	ArcFM Software	SO	3,978	89	1,083	306	541	1,731	228	1	0
1010000	ELEC PLANT IN SERV	3033220	MONARCH EMS/SCADA	SO	29,411	656	8,004	2,264	3,999	12,793	1,688	6	0
1010000	ELEC PLANT IN SERV	3033230	VREALIZE VMWARE - SHARED	SO	1,055	24	287	81	143	459	61	0	0
1010000	ELEC PLANT IN SERV	3033240	IEE - Itron Enterprise Addition	CN	3,688	88	1,151	256	274	1,764	155	0	0
1010000	ELEC PLANT IN SERV	3033250	AMI Metering Software	CN	23,140	555	7,224	1,605	1,718	11,067	972	0	0
1010000	ELEC PLANT IN SERV	3033260	Big Data & Analytics	SO	1,270	28	346	98	173	553	73	0	0
1010000	ELEC PLANT IN SERV	3033300	SECID - CUST SECURE WEB LOGIN	CN	1,085	26	339	75	81	519	46	0	0
1010000	ELEC PLANT IN SERV	3033310	C&T - Energy Trading System	SO	18,005	402	4,900	1,386	2,448	7,832	1,033	4	0
1010000	ELEC PLANT IN SERV	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	9,934	153	2,585	784	1,453	4,371	586	3	0
1010000	ELEC PLANT IN SERV	3033330	OR VHF (VPC) SPECTRUM	OR	4,071	0	4,071	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3033340	WA VHF (VPC) SPECTRUM	WA	2,021	0	0	2,021	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3033350	CA VHF (VPC) SPECTRUM	CA	472	472	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3033370	DISTRIBUTION INTANGIBLES	WYP	158	0	0	0	158	0	0	0	0
1010000	ELEC PLANT IN SERV	3033380	MISCELLANEOUS SMALL SOFTWARE PACKAGES	SG	1,601	25	417	126	234	704	94	0	0
1010000	ELEC PLANT IN SERV	3033390	RMT TRADE SYSTEM	SO	922	21	251	71	125	401	53	0	0
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	CA	9	9	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	CN	11	0	3	1	1	5	0	0	0
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	IDU	15	0	0	0	0	0	15	0	0
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	OR	14	0	14	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	SG	7,528	116	1,959	594	1,101	3,312	444	2	0
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	SO	40,051	894	10,900	3,083	5,446	17,422	2,299	8	0
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	UT	24	0	0	0	0	24	0	0	0
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	WA	15	0	0	15	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	WYP	243	0	0	0	243	0	0	0	0
1010000	ELEC PLANT IN SERV	3035320	HYDRO PLANT INTANGIBLES	SG	1,745	27	454	138	255	768	103	0	0
1010000	ELEC PLANT IN SERV	3035322	ACD–Call Center Automated Call Distribut	CN	4,132	99	1,290	287	307	1,976	174	0	0
1010000	ELEC PLANT IN SERV	3035330	OATI-OASIS INTERFACE	SO	1,240	28	337	95	169	539	71	0	0
1010000	ELEC PLANT IN SERV	3100000	LAND & LAND RIGHTS	SG	1,306	20	340	103	191	575	77	0	0
1010000	ELEC PLANT IN SERV	3101000	LAND OWNED IN FEE	SG	12,851	197	3,344	1,014	1,880	5,654	758	4	0
1010000	ELEC PLANT IN SERV	3102000	LAND RIGHTS	SG	43,158	663	11,231	3,406	6,312	18,988	2,545	12	0
1010000	ELEC PLANT IN SERV	3103000	WATER RIGHTS	SG	35,638	548	9,274	2,813	5,212	15,680	2,102	10	0
1010000	ELEC PLANT IN SERV	3108000	FEE LAND - LEASED	SG	37	1	10	3	5	16	2	0	0
1010000	ELEC PLANT IN SERV	3110000	STRUCTURES AND IMPROVEMENTS	SG	1,036,526	15,928	269,731	81,803	151,595	456,046	61,129	294	0
1010000	ELEC PLANT IN SERV	3120000	BOILER PLANT EQUIPMENT	SG	4,611,890	70,871	1,200,135	363,972	674,504	2,029,116	271,985	1,307	0
1010000	ELEC PLANT IN SERV	3140000	TURBOGENERATOR UNITS	SG	1,001,421	15,389	260,596	79,033	146,461	440,600	59,059	284	0
1010000	ELEC PLANT IN SERV	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	488,132	7,501	127,025	38,524	71,391	214,766	28,787	138	0
1010000	ELEC PLANT IN SERV	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	62	1	16	5	9	27	4	0	0
1010000	ELEC PLANT IN SERV	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	33,035	508	8,597	2,607	4,831	14,535	1,948	9	0
1010000	ELEC PLANT IN SERV	3300000	LAND AND LAND RIGHTS	SG-U	172	3	45	14	25	76	10	0	0
1010000	ELEC PLANT IN SERV	3301000	LAND OWNED IN FEE	SG-P	21,151	325	5,504	1,669	3,093	9,306	1,247	6	0
1010000	ELEC PLANT IN SERV	3301000	LAND OWNED IN FEE	SG-U	5,780	89	1,504	456	845	2,543	341	2	0
1010000	ELEC PLANT IN SERV	3302000	LAND RIGHTS	SG-P	8,035	123	2,091	634	1,175	3,535	474	2	0
1010000	ELEC PLANT IN SERV	3302000	LAND RIGHTS	SG-U	365	6	95	29	53	160	22	0	0

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1010000	ELEC PLANT IN SERV	3303000	WATER RIGHTS	SG-P	21	0	5	2	3	9	1	0	0
1010000	ELEC PLANT IN SERV	3303000	WATER RIGHTS	SG-U	140	2	36	11	20	61	8	0	0
1010000	ELEC PLANT IN SERV	3304000	FLOOD RIGHTS	SG-P	257	4	67	20	38	113	15	0	0
1010000	ELEC PLANT IN SERV	3304000	FLOOD RIGHTS	SG-U	91	1	24	7	13	40	5	0	0
1010000	ELEC PLANT IN SERV	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	310	5	81	24	45	136	18	0	0
1010000	ELEC PLANT IN SERV	3310000	STRUCTURES AND IMPROVE	SG-P	7	0	2	1	1	3	0	0	0
1010000	ELEC PLANT IN SERV	3310000	STRUCTURES AND IMPROVE	SG-U	7,209	111	1,876	569	1,054	3,172	425	2	0
1010000	ELEC PLANT IN SERV	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	64,903	997	16,889	5,122	9,492	28,556	3,828	18	0
1010000	ELEC PLANT IN SERV	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	7,354	113	1,914	580	1,076	3,236	434	2	0
1010000	ELEC PLANT IN SERV	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	160,439	2,465	41,751	12,662	23,465	70,589	9,462	45	0
1010000	ELEC PLANT IN SERV	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	364	6	95	29	53	160	21	0	0
1010000	ELEC PLANT IN SERV	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	21,232	326	5,525	1,676	3,105	9,341	1,252	6	0
1010000	ELEC PLANT IN SERV	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	2,026	31	527	160	296	891	119	1	0
1010000	ELEC PLANT IN SERV	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	14,659	225	3,815	1,157	2,144	6,450	865	4	0
1010000	ELEC PLANT IN SERV	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	6,301	97	1,640	497	922	2,772	372	2	0
1010000	ELEC PLANT IN SERV	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	24,569	378	6,393	1,939	3,593	10,810	1,449	7	0
1010000	ELEC PLANT IN SERV	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	385,007	5,916	100,189	30,385	56,308	169,393	22,706	109	0
1010000	ELEC PLANT IN SERV	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	70,537	1,084	18,356	5,567	10,316	31,035	4,160	20	0
1010000	ELEC PLANT IN SERV	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	23,764	365	6,184	1,875	3,476	10,455	1,401	7	0
1010000	ELEC PLANT IN SERV	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	411	6	107	32	60	181	24	0	0
1010000	ELEC PLANT IN SERV	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	209	3	54	16	31	92	12	0	0
1010000	ELEC PLANT IN SERV	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	63	1	17	5	9	28	4	0	0
1010000	ELEC PLANT IN SERV	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	93,045	1,430	24,213	7,343	13,608	40,937	5,487	26	0
1010000	ELEC PLANT IN SERV	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	46,069	708	11,988	3,636	6,738	20,269	2,717	13	0
1010000	ELEC PLANT IN SERV	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	67,816	1,042	17,647	5,352	9,918	29,837	3,999	19	0
1010000	ELEC PLANT IN SERV	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	14,147	217	3,681	1,116	2,069	6,224	834	4	0
1010000	ELEC PLANT IN SERV	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	2,896	45	754	229	424	1,274	171	1	0
1010000	ELEC PLANT IN SERV	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	64	1	17	5	9	28	4	0	0
1010000	ELEC PLANT IN SERV	3350000	MISC POWER PLANT EQUIP	SG-U	173	3	45	14	25	76	10	0	0
1010000	ELEC PLANT IN SERV	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	2,296	35	597	181	336	1,010	135	1	0
1010000	ELEC PLANT IN SERV	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	22,746	350	5,919	1,795	3,327	10,008	1,341	6	0
1010000	ELEC PLANT IN SERV	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	2,216	34	577	175	324	975	131	1	0
1010000	ELEC PLANT IN SERV	3401000	LAND OWNED IN FEE	OR	75	0	75	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3401000	LAND OWNED IN FEE	SG	12,649	194	3,291	998	1,850	5,565	746	4	0
1010000	ELEC PLANT IN SERV	3403000	WATER RIGHTS - OTHER PRODUCTION	SG	32,709	503	8,512	2,581	4,784	14,391	1,929	9	0
1010000	ELEC PLANT IN SERV	3410000	STRUCTURES & IMPROVEMENTS	SG	228,344	3,509	59,421	18,021	33,396	100,466	13,467	65	0
1010000	ELEC PLANT IN SERV	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	16,188	249	4,213	1,278	2,368	7,122	955	5	0
1010000	ELEC PLANT IN SERV	3430000	PRIME MOVERS	SG	2,924,544	44,942	761,043	230,806	427,724	1,286,726	172,474	829	0
1010000	ELEC PLANT IN SERV	3440000	GENERATORS	SG	475,410	7,306	123,714	37,520	69,530	209,168	28,037	135	0
1010000	ELEC PLANT IN SERV	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	327,537	5,033	85,234	25,849	47,903	144,108	19,316	93	0
1010000	ELEC PLANT IN SERV	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	15,924	245	4,144	1,257	2,329	7,006	939	5	0
1010000	ELEC PLANT IN SERV	3500000	LAND AND LAND RIGHTS	SG	841	13	219	66	123	370	50	0	0
1010000	ELEC PLANT IN SERV	3501000	LAND OWNED IN FEE	SG	59,466	914	15,475	4,693	8,697	26,164	3,507	17	0

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1010000	ELEC PLANT IN SERV	3502000	LAND RIGHTS	SG	211,132	3,244	54,942	16,663	30,879	92,893	12,451	60	0
1010000	ELEC PLANT IN SERV	3520000	STRUCTURES & IMPROVEMENTS	SG	277,949	4,271	72,330	21,936	40,651	122,291	16,392	79	0
1010000	ELEC PLANT IN SERV	3530000	STATION EQUIPMENT	SG	2,012,333	30,924	523,662	158,814	294,310	885,376	118,677	570	0
1010000	ELEC PLANT IN SERV	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	164,162	2,523	42,719	12,956	24,009	72,227	9,681	47	0
1010000	ELEC PLANT IN SERV	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	22,576	347	5,875	1,782	3,302	9,933	1,331	6	0
1010000	ELEC PLANT IN SERV	3540000	TOWERS AND FIXTURES	SG	1,303,550	20,032	339,218	102,877	190,648	573,529	76,876	369	0
1010000	ELEC PLANT IN SERV	3550000	POLES AND FIXTURES	SG	991,676	15,239	258,060	78,263	145,036	436,313	58,484	281	0
1010000	ELEC PLANT IN SERV	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	1,270,493	19,524	330,616	100,268	185,814	558,985	74,927	360	0
1010000	ELEC PLANT IN SERV	3570000	UNDERGROUND CONDUIT	SG	3,787	58	986	299	554	1,666	223	1	0
1010000	ELEC PLANT IN SERV	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	8,035	123	2,091	634	1,175	3,535	474	2	0
1010000	ELEC PLANT IN SERV	3590000	ROADS AND TRAILS	SG	11,937	183	3,106	942	1,746	5,252	704	3	0
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	IDU	1	0	0	0	0	0	1	0	0
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	OR	8	0	8	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	UT	168	0	0	0	0	168	0	0	0
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	WYP	4	0	0	0	4	0	0	0	0
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	WYU	2	0	0	0	2	0	0	0	0
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	CA	729	729	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	IDU	502	0	0	0	0	0	502	0	0
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	OR	9,052	0	9,052	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	UT	25,836	0	0	0	0	25,836	0	0	0
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WA	1,401	0	0	1,401	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WYP	675	0	0	0	675	0	0	0	0
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WYU	48	0	0	0	48	0	0	0	0
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	CA	1,091	1,091	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	IDU	1,333	0	0	0	0	0	1,333	0	0
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	OR	5,131	0	5,131	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	UT	11,126	0	0	0	0	11,126	0	0	0
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WA	467	0	0	467	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WYP	2,163	0	0	0	2,163	0	0	0	0
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WYU	4,016	0	0	0	4,016	0	0	0	0
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	CA	5,234	5,234	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	IDU	3,366	0	0	0	0	0	3,366	0	0
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	OR	32,578	0	32,578	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	UT	57,790	0	0	0	0	57,790	0	0	0
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WA	6,114	0	0	6,114	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WYP	12,248	0	0	0	12,248	0	0	0	0
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WYU	4,812	0	0	0	4,812	0	0	0	0
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	CA	30,257	30,257	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	IDU	36,911	0	0	0	0	0	36,911	0	0
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	OR	254,290	0	254,290	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	UT	477,238	0	0	0	0	477,238	0	0	0
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WA	75,081	0	0	75,081	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WYP	117,942	0	0	0	117,942	0	0	0	0

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1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WYU	18,304	0	0	0	18,304	0	0	0	0
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	404	404	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	565	0	0	0	0	0	565	0	0
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	4,022	0	4,022	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	7,040	0	0	0	0	7,040	0	0	0
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	1,294	0	0	1,294	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	1,948	0	0	0	1,948	0	0	0	0
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	235	0	0	0	235	0	0	0	0
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	CA	71,890	71,890	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	IDU	92,511	0	0	0	0	0	92,511	0	0
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	OR	395,747	0	395,747	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	UT	398,365	0	0	0	0	398,365	0	0	0
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WA	110,587	0	0	110,587	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WYP	136,687	0	0	0	136,687	0	0	0	0
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WYU	28,490	0	0	0	28,490	0	0	0	0
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	36,105	36,105	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	39,762	0	0	0	0	0	39,762	0	0
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	272,505	0	272,505	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	245,730	0	0	0	0	245,730	0	0	0
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	74,587	0	0	74,587	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	102,433	0	0	0	102,433	0	0	0	0
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	14,078	0	0	0	14,078	0	0	0	0
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	CA	18,469	18,469	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	IDU	10,499	0	0	0	0	0	10,499	0	0
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	OR	97,779	0	97,779	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	UT	213,643	0	0	0	0	213,643	0	0	0
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WA	18,900	0	0	18,900	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WYP	25,100	0	0	0	25,100	0	0	0	0
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WYU	5,052	0	0	0	5,052	0	0	0	0
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	20,734	20,734	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	29,031	0	0	0	0	0	29,031	0	0
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	190,342	0	190,342	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	574,341	0	0	0	0	574,341	0	0	0
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	29,339	0	0	29,339	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	46,904	0	0	0	46,904	0	0	0	0
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	18,509	0	0	0	18,509	0	0	0	0
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	CA	55,201	55,201	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	IDU	84,145	0	0	0	0	0	84,145	0	0
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	OR	460,559	0	460,559	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	UT	558,275	0	0	0	0	558,275	0	0	0
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WA	115,817	0	0	115,817	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WYP	110,769	0	0	0	110,769	0	0	0	0
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WYU	15,569	0	0	0	15,569	0	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	CA	10,481	10,481	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	IDU	8,882	0	0	0	0	0	8,882	0	0
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	OR	98,104	0	98,104	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	UT	91,894	0	0	0	0	91,894	0	0	0
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WA	24,101	0	0	24,101	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WYP	17,622	0	0	0	17,622	0	0	0	0
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WYU	3,537	0	0	0	3,537	0	0	0	0
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	CA	16,839	16,839	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	IDU	34,684	0	0	0	0	0	34,684	0	0
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	OR	200,105	0	200,105	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	UT	242,557	0	0	0	0	242,557	0	0	0
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WA	42,742	0	0	42,742	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WYP	34,921	0	0	0	34,921	0	0	0	0
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WYU	12,066	0	0	0	12,066	0	0	0	0
1010000	ELEC PLANT IN SERV	3700000	METERS	CA	8,213	8,213	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3700000	METERS	IDU	16,315	0	0	0	0	0	16,315	0	0
1010000	ELEC PLANT IN SERV	3700000	METERS	OR	91,509	0	91,509	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3700000	METERS	UT	91,952	0	0	0	0	91,952	0	0	0
1010000	ELEC PLANT IN SERV	3700000	METERS	WA	13,282	0	0	13,282	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3700000	METERS	WYP	13,573	0	0	0	13,573	0	0	0	0
1010000	ELEC PLANT IN SERV	3700000	METERS	WYU	2,441	0	0	0	2,441	0	0	0	0
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	CA	280	280	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	170	0	0	0	0	0	170	0	0
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	OR	2,639	0	2,639	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	UT	4,229	0	0	0	0	4,229	0	0	0
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WA	512	0	0	512	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	820	0	0	0	820	0	0	0	0
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	155	0	0	0	155	0	0	0	0
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	778	778	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	748	0	0	0	0	0	748	0	0
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	24,073	0	24,073	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	21,466	0	0	0	0	21,466	0	0	0
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	4,798	0	0	4,798	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	8,530	0	0	0	8,530	0	0	0	0
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	2,271	0	0	0	2,271	0	0	0	0
1010000	ELEC PLANT IN SERV	3890000	LAND AND LAND RIGHTS	IDU	89	0	0	0	0	0	89	0	0
1010000	ELEC PLANT IN SERV	3890000	LAND AND LAND RIGHTS	OR	228	0	228	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3890000	LAND AND LAND RIGHTS	UT	1,327	0	0	0	0	1,327	0	0	0
1010000	ELEC PLANT IN SERV	3890000	LAND AND LAND RIGHTS	WYU	434	0	0	0	434	0	0	0	0
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	CA	997	997	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	CN	1,129	27	352	78	84	540	47	0	0
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	IDU	100	0	0	0	0	0	100	0	0
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	OR	5,886	0	5,886	0	0	0	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	SG	0	0	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	SO	7,516	168	2,046	579	1,022	3,269	431	2	0
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	UT	2,669	0	0	0	0	2,669	0	0	0
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	WA	1,099	0	0	1,099	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	WYP	1,756	0	0	0	1,756	0	0	0	0
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	WYU	221	0	0	0	221	0	0	0	0
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	IDU	5	0	0	0	0	0	5	0	0
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	SG	1	0	0	0	0	1	0	0	0
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	UT	84	0	0	0	0	84	0	0	0
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	WYP	52	0	0	0	52	0	0	0	0
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	WYU	22	0	0	0	22	0	0	0	0
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	CA	3,553	3,553	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	CN	8,208	197	2,562	569	609	3,925	345	0	0
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	IDU	11,372	0	0	0	0	0	11,372	0	0
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	OR	34,175	0	34,175	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SE	1,236	18	310	93	197	536	81	0	0
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SG	7,609	117	1,980	601	1,113	3,348	449	2	0
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SO	91,904	2,051	25,012	7,075	12,496	39,977	5,274	19	0
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	UT	44,155	0	0	0	0	44,155	0	0	0
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WA	11,538	0	0	11,538	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WYP	10,482	0	0	0	10,482	0	0	0	0
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WYU	3,887	0	0	0	3,887	0	0	0	0
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	506	506	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	IDU	334	0	0	0	0	0	334	0	0
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	5,336	0	5,336	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	4,644	104	1,264	358	631	2,020	267	1	0
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	19	0	0	0	0	19	0	0	0
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	2,407	0	0	2,407	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	4,537	0	0	0	4,537	0	0	0	0
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	CA	110	110	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	CN	1,179	28	368	82	88	564	50	0	0
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	IDU	94	0	0	0	0	0	94	0	0
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	OR	1,522	0	1,522	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	SE	5	0	1	0	1	2	0	0	0
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	SG	1,448	22	377	114	212	637	85	0	0
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	SO	12,177	272	3,314	937	1,656	5,297	699	2	0
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	UT	753	0	0	0	0	753	0	0	0
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WA	63	0	0	63	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WYP	539	0	0	0	539	0	0	0	0
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WYU	34	0	0	0	34	0	0	0	0
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	32	32	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	2,861	69	893	198	212	1,368	120	0	0
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	289	0	0	0	0	0	289	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	667	0	667	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	5	0	1	0	1	2	0	0	0
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	1,683	26	438	133	246	741	99	0	0
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	39,203	875	10,669	3,018	5,330	17,053	2,250	8	0
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	494	0	0	0	0	494	0	0	0
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	246	0	0	246	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	1,634	0	0	0	1,634	0	0	0	0
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	27	0	0	0	27	0	0	0	0
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	CN	0	0	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	IDU	1	0	0	0	0	0	1	0	0
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	OR	3	0	3	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	SG	56	1	15	4	8	25	3	0	0
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	SO	76	2	21	6	10	33	4	0	0
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	UT	8	0	0	0	0	8	0	0	0
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	WYP	2	0	0	0	2	0	0	0	0
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	WYU	8	0	0	0	8	0	0	0	0
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	CA	41	41	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	IDU	226	0	0	0	0	0	226	0	0
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	OR	1,806	0	1,806	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SE	52	1	13	4	8	23	3	0	0
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	476	7	124	38	70	210	28	0	0
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	609	14	166	47	83	265	35	0	0
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	2,614	0	0	0	0	2,614	0	0	0
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	206	0	0	206	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	WYP	389	0	0	0	389	0	0	0	0
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	OR	116	0	116	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	SG	35	1	9	3	5	15	2	0	0
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	SO	122	3	33	9	17	53	7	0	0
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	UT	281	0	0	0	0	281	0	0	0
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	WA	31	0	0	31	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	WYP	41	0	0	0	41	0	0	0	0
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	CA	460	460	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	1,580	0	0	0	0	0	1,580	0	0
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	5,813	0	5,813	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	170	2	43	13	27	74	11	0	0
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	8,006	123	2,083	632	1,171	3,523	472	2	0
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	1,425	32	388	110	194	620	82	0	0
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	7,309	0	0	0	0	7,309	0	0	0
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	1,107	0	0	1,107	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYP	1,787	0	0	0	1,787	0	0	0	0
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	396	0	0	0	396	0	0	0	0
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	985	985	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	3,453	0	0	0	0	0	3,453	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	12,327	0	12,327	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	215	3	54	16	34	93	14	0	0
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	6,786	104	1,766	536	992	2,986	400	2	0
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	561	13	153	43	76	244	32	0	0
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	17,969	0	0	0	0	17,969	0	0	0
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	2,847	0	0	2,847	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYP	4,278	0	0	0	4,278	0	0	0	0
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	1,275	0	0	0	1,275	0	0	0	0
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	OR	269	0	269	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	SE	4	0	1	0	1	2	0	0	0
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	SG	3,925	60	1,021	310	574	1,727	231	1	0
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	UT	125	0	0	0	0	125	0	0	0
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	CA	481	481	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	IDU	1,238	0	0	0	0	0	1,238	0	0
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	OR	3,760	0	3,760	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SE	41	1	10	3	7	18	3	0	0
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SG	1,443	22	376	114	211	635	85	0	0
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SO	852	19	232	66	116	371	49	0	0
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	UT	7,154	0	0	0	0	7,154	0	0	0
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WA	883	0	0	883	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WYP	2,994	0	0	0	2,994	0	0	0	0
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WYU	384	0	0	0	384	0	0	0	0
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	104	104	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	88	0	0	0	0	0	88	0	0
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	402	0	402	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SE	6	0	2	0	1	3	0	0	0
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SG	853	13	222	67	125	375	50	0	0
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	35	1	9	3	5	15	2	0	0
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	266	0	0	0	0	266	0	0	0
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WA	83	0	0	83	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYP	288	0	0	0	288	0	0	0	0
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	16	0	0	0	16	0	0	0	0
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	317	0	317	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	376	6	98	30	55	165	22	0	0
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	296	7	81	23	40	129	17	0	0
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	1,692	0	0	0	0	1,692	0	0	0
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	170	0	0	170	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	WYP	86	0	0	0	86	0	0	0	0
1010000	ELEC PLANT IN SERV	3923000	TRANSPORTATION EQUIPMENT	SO	2,993	67	815	230	407	1,302	172	1	0
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	CA	180	180	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	IDU	495	0	0	0	0	0	495	0	0
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	OR	2,635	0	2,635	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	SG	5,914	91	1,539	467	865	2,602	349	2	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	SO	255	6	69	20	35	111	15	0	0
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	UT	3,328	0	0	0	0	3,328	0	0	0
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WA	697	0	0	697	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WYP	1,104	0	0	0	1,104	0	0	0	0
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WYU	1	0	0	0	1	0	0	0	0
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	782	782	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	2,037	0	0	0	0	0	2,037	0	0
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	10,475	0	10,475	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	109	2	27	8	17	47	7	0	0
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	24,242	373	6,308	1,913	3,545	10,666	1,430	7	0
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	2,127	47	579	164	289	925	122	0	0
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	14,177	0	0	0	0	14,177	0	0	0
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	2,744	0	0	2,744	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	3,747	0	0	0	3,747	0	0	0	0
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	402	0	0	0	402	0	0	0	0
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	CA	305	305	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	IDU	1,293	0	0	0	0	0	1,293	0	0
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	OR	7,888	0	7,888	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SE	1,258	18	316	95	201	545	82	0	0
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SG	6,615	102	1,721	522	968	2,911	390	2	0
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SO	4,974	111	1,354	383	676	2,163	285	1	0
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	UT	7,829	0	0	0	0	7,829	0	0	0
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WA	1,277	0	0	1,277	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WYP	2,477	0	0	0	2,477	0	0	0	0
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WYU	121	0	0	0	121	0	0	0	0
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	CA	1,549	1,549	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	IDU	3,104	0	0	0	0	0	3,104	0	0
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	OR	12,482	0	12,482	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SG	257	4	67	20	38	113	15	0	0
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SO	1,202	27	327	93	163	523	69	0	0
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	UT	12,833	0	0	0	0	12,833	0	0	0
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WA	2,838	0	0	2,838	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYP	5,205	0	0	0	5,205	0	0	0	0
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYU	802	0	0	0	802	0	0	0	0
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	CA	173	173	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	171	0	0	0	0	0	171	0	0
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	OR	892	0	892	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	124	2	32	10	18	55	7	0	0
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	581	0	0	0	0	581	0	0	0
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	210	0	0	0	210	0	0	0	0
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	CA	1,326	1,326	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	2,706	0	0	0	0	0	2,706	0	0
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	12,694	0	12,694	0	0	0	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	1,239	19	322	98	181	545	73	0	0
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SO	1,926	43	524	148	262	838	111	0	0
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	14,493	0	0	0	0	14,493	0	0	0
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WA	3,092	0	0	3,092	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYP	5,510	0	0	0	5,510	0	0	0	0
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYU	830	0	0	0	830	0	0	0	0
1010000	ELEC PLANT IN SERV	3961000	CRANES	OR	413	0	413	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3961000	CRANES	SG	3,546	54	923	280	519	1,560	209	1	0
1010000	ELEC PLANT IN SERV	3961000	CRANES	UT	3	0	0	0	0	3	0	0	0
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	OR	1,217	0	1,217	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SG	34,245	526	8,912	2,703	5,008	15,067	2,020	10	0
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SO	1,321	29	360	102	180	575	76	0	0
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	1,476	0	0	0	0	1,476	0	0	0
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WYP	900	0	0	0	900	0	0	0	0
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	CA	843	843	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	3,182	0	0	0	0	0	3,182	0	0
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	10,127	0	10,127	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	325	5	85	26	48	143	19	0	0
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	949	21	258	73	129	413	54	0	0
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	UT	15,920	0	0	0	0	15,920	0	0	0
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WA	2,192	0	0	2,192	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	4,625	0	0	0	4,625	0	0	0	0
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	993	0	0	0	993	0	0	0	0
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	CA	529	529	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	IDU	1,429	0	0	0	0	0	1,429	0	0
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	OR	2,788	0	2,788	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SE	237	3	59	18	38	103	16	0	0
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SG	6,955	107	1,810	549	1,017	3,060	410	2	0
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	695	16	189	53	94	302	40	0	0
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	UT	5,086	0	0	0	0	5,086	0	0	0
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WA	817	0	0	817	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYP	1,830	0	0	0	1,830	0	0	0	0
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYU	780	0	0	0	780	0	0	0	0
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	CA	6,219	6,219	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	CN	3,849	92	1,201	267	286	1,841	162	0	0
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	IDU	11,198	0	0	0	0	0	11,198	0	0
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	OR	73,945	0	73,945	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SE	259	4	65	20	41	112	17	0	0
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SG	173,763	2,670	45,218	13,713	25,413	76,451	10,248	49	0
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SO	92,565	2,066	25,192	7,126	12,586	40,264	5,312	19	0
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	UT	61,299	0	0	0	0	61,299	0	0	0
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	WA	13,244	0	0	13,244	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	WYP	25,342	0	0	0	25,342	0	0	0	0

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1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	WYU	5,956	0	0	0	5,956	0	0	0	0
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	CA	313	313	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	IDU	328	0	0	0	0	0	328	0	0
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	OR	2,533	0	2,533	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	SE	82	1	21	6	13	36	5	0	0
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	SG	4,218	65	1,098	333	617	1,856	249	1	0
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	SO	495	11	135	38	67	216	28	0	0
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	UT	1,759	0	0	0	0	1,759	0	0	0
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	WA	542	0	0	542	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	WYP	720	0	0	0	720	0	0	0	0
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	WYU	104	0	0	0	104	0	0	0	0
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	CA	50	50	0	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	CN	82	2	26	6	6	39	3	0	0
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	IDU	82	0	0	0	0	0	82	0	0
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	OR	1,108	0	1,108	0	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SE	4	0	1	0	1	2	0	0	0
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SG	2,714	42	706	214	397	1,194	160	1	0
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SO	2,205	49	600	170	300	959	127	0	0
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	UT	1,343	0	0	0	0	1,343	0	0	0
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WA	181	0	0	181	0	0	0	0	0
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WYP	186	0	0	0	186	0	0	0	0
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WYU	17	0	0	0	17	0	0	0	0
1010000	ELEC PLANT IN SERV	3992100	LAND OWNED IN FEE	SE	1,855	27	466	139	296	804	122	1	0
1010000 Total					**27,945,143**	**613,790**	**7,636,623**	**2,162,614**	**3,802,772**	**12,126,378**	**1,597,340**	**5,625**	**0**
1019000	ELEC PLT IN SERV-OTH	140109	Land-Non-Rec	SG	-661	-10	-172	-52	-97	-291	-39	0	0
1019000	ELEC PLT IN SERV-OTH	140129	ELECTRIC PLANT IN SERVICE - OTHER	SO	-1,385	-31	-377	-107	-188	-602	-79	0	0
1019000	ELEC PLT IN SERV-OTH	140139	PRODUCTION PLANT-NON-RECONCILED	SG	-14,223	-219	-3,701	-1,122	-2,080	-6,258	-839	-4	0
1019000	ELEC PLT IN SERV-OTH	140149	TRANS PLANT NON-RECONCILED	SG	-3,436	-53	-894	-271	-503	-1,512	-203	-1	0
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	CA	-67	-67	0	0	0	0	0	0	0
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	IDU	-158	0	0	0	0	0	-158	0	0
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	OR	-1,007	0	-1,007	0	0	0	0	0	0
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	UT	-1,641	0	0	0	0	-1,641	0	0	0
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	WA	-353	0	0	-353	0	0	0	0	0
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	WYU	-349	0	0	0	-349	0	0	0	0
1019000 Total					**-23,280**	**-379**	**-6,152**	**-1,905**	**-3,216**	**-10,304**	**-1,318**	**-5**	**0**
1020000	ELEC PL PUR OR SLD	0	ELECTRIC PLANT PURCHASED OR SOLD	SG	-553	-9	-144	-44	-81	-243	-33	0	0
1020000	ELEC PL PUR OR SLD	140708	CONTRA ELEC PLANT PURCH OR SOLD - LOSS	SG	553	9	144	44	81	243	33	0	0
1020000 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	CA	1,084	1,084	0	0	0	0	0	0	0
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	IDU	3,197	0	0	0	0	0	3,197	0	0
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	OR	16,312	0	16,312	0	0	0	0	0	0
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	UT	31,617	0	0	0	0	31,617	0	0	0
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WA	4,899	0	0	4,899	0	0	0	0	0

PACIFICORP

Electric Plant In Service with Unclassified
Balances as of June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WYU	7,887	0	0	0	7,887	0	0	0	0
1061000 Total					**64,995**	**1,084**	**16,312**	**4,899**	**7,887**	**31,617**	**3,197**	**0**	**0**
1062000	TRAN COMP CONST NOT	0	TRANSM COMPLETED CONSTRUCTN NOT CLASSIFI	SG	112,533	1,729	29,284	8,881	16,458	49,512	6,637	32	0
1062000 Total					**112,533**	**1,729**	**29,284**	**8,881**	**16,458**	**49,512**	**6,637**	**32**	**0**
1063000	PROD COMP CONST NOT	0	PROD COMPLETED CONSTRUCTN NOT CLASSIFIED	SG	69,880	1,074	18,185	5,515	10,220	30,746	4,121	20	0
1063000 Total					**69,880**	**1,074**	**18,185**	**5,515**	**10,220**	**30,746**	**4,121**	**20**	**0**
1064000	GEN COMP CONST NOT	0	GENERAL COMPLETED CONSTRUCTN NOT CLASSIF	SO	40,822	911	11,110	3,143	5,550	17,757	2,343	8	0
1064000 Total					**40,822**	**911**	**11,110**	**3,143**	**5,550**	**17,757**	**2,343**	**8**	**0**
Grand Total					**28,210,093**	**618,209**	**7,705,361**	**2,183,147**	**3,839,671**	**12,245,706**	**1,612,319**	**5,680**	**0**

PACIFICORP

Capital Lease

Balances as of June 2019
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	2,463	0	2,463	0	0	0	0	0	0
1011000	PRPTY UND CPTL LSS	3908220	(FINANCE LEASES-BLDGS)	SO	2,380	53	648	183	324	1,035	137	0	0
1011000	PRPTY UND CPTL LSS	3908230	(FINANCE LEASES-GAS)	SG	12,159	187	3,164	960	1,778	5,350	717	3	0
1011000 Total					**17,002**	**240**	**6,275**	**1,143**	**2,102**	**6,385**	**854**	**4**	**0**
1011500	CAP LEASES–ACCM AMRT	3908220	(FINANCE LEASES-BLDGS)	OR	-205	0	-205	0	0	0	0	0	0
1011500	CAP LEASES–ACCM AMRT	3908220	(FINANCE LEASES-BLDGS)	SO	-492	-11	-134	-38	-67	-214	-28	0	0
1011500	CAP LEASES–ACCM AMRT	3908230	(FINANCE LEASES-GAS)	SG	-456	-7	-119	-36	-67	-200	-27	0	0
1011500 Total					**-1,153**	**-18**	**-458**	**-74**	**-134**	**-415**	**-55**	**0**	**0**
1011900	PRPTY UND CPTL LSS-O	142785	FINANCE LEASE ROU ASSETS (COST) - PPAS	UT	11,714	0	0	0	0	11,714	0	0	0
1011900	PRPTY UND CPTL LSS-O	142794	FIN LEASE ROU ASSETS (COST)-OTHER-TEMP	OR	3,146	0	3,146	0	0	0	0	0	0
1011900	PRPTY UND CPTL LSS-O	142794	FIN LEASE ROU ASSETS (COST)-OTHER-TEMP	SG	4,793	74	1,247	378	701	2,109	283	1	0
1011900	PRPTY UND CPTL LSS-O	142794	FIN LEASE ROU ASSETS (COST)-OTHER-TEMP	SO	10,284	230	2,799	792	1,398	4,474	590	2	0
1011900 Total					**29,937**	**303**	**7,192**	**1,170**	**2,099**	**18,296**	**873**	**3**	**0**
1011950	CAP LEASES–ACCM AMRT	142885	Finance Lease ROU Assets (A/D) - PPAs	UT	-7,961	0	0	0	0	-7,961	0	0	0
1011950	CAP LEASES–ACCM AMRT	142894	Fin Lease ROU Assets (A/D)-Other-Temp	OR	-3,146	0	-3,146	0	0	0	0	0	0
1011950	CAP LEASES–ACCM AMRT	142894	Fin Lease ROU Assets (A/D)-Other-Temp	SG	-4,793	-74	-1,247	-378	-701	-2,109	-283	-1	0
1011950	CAP LEASES–ACCM AMRT	142894	Fin Lease ROU Assets (A/D)-Other-Temp	SO	-10,284	-230	-2,799	-792	-1,398	-4,474	-590	-2	0
1011950 Total					**-26,184**	**-303**	**-7,192**	**-1,170**	**-2,099**	**-14,543**	**-873**	**-3**	**0**
Grand Total					**19,602**	**222**	**5,817**	**1,069**	**1,968**	**9,723**	**799**	**4**	**0**

PACIFICORP

Plant Held for Future Use

Balances as of June 2019
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	137	2,322	704	1,305	3,926	526	3	0
1050000	EL PLT HLD FTR USE	3501000	LAND OWNED IN FEE	SG	2,903	45	755	229	425	1,277	171	1	0
1050000	EL PLT HLD FTR USE	3502000	LAND RIGHTS	SG	755	12	196	60	110	332	45	0	0
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	CA	683	683	0	0	0	0	0	0	0
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	OR	3,918	0	3,918	0	0	0	0	0	0
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	UT	5,731	0	0	0	0	5,731	0	0	0
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	WYP	1	0	0	0	1	0	0	0	0
1050000	EL PLT HLD FTR USE	3891000	LAND OWNED IN FEE	OR	3,508	0	3,508	0	0	0	0	0	0
1050000 Total					**26,421**	**877**	**10,700**	**993**	**1,841**	**11,266**	**742**	**4**	**0**
Grand Total					**26,421**	**877**	**10,700**	**993**	**1,841**	**11,266**	**742**	**4**	**0**

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Deferred Debits
Balances as of June 2019
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	34	589	176	375	1,017	154	1	0
1861000	MS DEF DB-OTH WIP	185017	ERCs - Impairment Reserve	SE	(2,040)	(30)	(512)	(153)	(326)	(884)	(134)	(1)	0
1861000 Total					**307**	**4**	**77**	**23**	**49**	**133**	**20**	**0**	**0**
1861200	FINANCING COSTS DEFR	185025	FINANCING COST DEFERRED	SO	1	0	0	0	0	1	0	0	0
1861200	FINANCING COSTS DEFR	185026	DEFERRED - S-3 SHELF REGISTRATION COSTS	SO	164	4	44	13	22	71	9	0	0
1861200	FINANCING COSTS DEFR	185027	UNAMORTIZED CREDIT AGREEMENT COSTS	OTHER	2,020	0	0	0	0	0	0	0	2,020
1861200	FINANCING COSTS DEFR	185029	UNAMORTIZED PCRB MADE CONVERSION COSTS	OTHER	347	0	0	0	0	0	0	0	347
1861200	FINANCING COSTS DEFR	185030	UNAMORTIZED '94 SERIES RESTRUCTURING COS	OTHER	313	0	0	0	0	0	0	0	313
1861200 Total					**2,846**	**4**	**45**	**13**	**22**	**72**	**9**	**0**	**2,681**
1865000	DEF COAL MINE COSTS	184414	DEFERRED COAL COSTS - WYODAK SETTLEMENT	SE	1,173	17	294	88	187	509	77	0	0
1865000 Total					**1,173**	**17**	**294**	**88**	**187**	**509**	**77**	**0**	**0**
1867000	MSC DF DR-BAL TRAN	134300	DEFERRED CHARGES	SE	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0
1867000 Total					**(1)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**0**
1868000	MISC DF DR-OTH-CST	134305	Oth Def Chrg - IT Licenses/Maintenance	OTHER	123	0	0	0	0	0	0	0	123
1868000	MISC DF DR-OTH-CST	185306	TGS BUYOUT	SG	9	0	2	1	1	4	1	0	0
1868000	MISC DF DR-OTH-CST	185313	MEAD-PHOENIX-AVAILABILITY & TRANS CHARGE	SG	10,141	156	2,639	800	1,483	4,462	598	3	0
1868000	MISC DF DR-OTH-CST	185335	LACOMB IRRIGATION	SG	118	2	31	9	17	52	7	0	0
1868000	MISC DF DR-OTH-CST	185336	BOGUS CREEK	SG	850	13	221	67	124	374	50	0	0
1868000	MISC DF DR-OTH-CST	185337	POINT-TO-POINT TRANS RESERVATIONS	SG	911	14	237	72	133	401	54	0	0
1868000	MISC DF DR-OTH-CST	185351	BPA LT TRANSMISSION PREPAID	OTHER	943	0	0	0	0	0	0	0	943
1868000	MISC DF DR-OTH-CST	185359	LT Lake Side 2 Maint. Prepayment	SG	12,165	187	3,166	960	1,779	5,352	717	3	0
1868000	MISC DF DR-OTH-CST	185360	LT LAKE SIDE MAINT PREPAYMENT	SG	24,986	384	6,502	1,972	3,654	10,993	1,474	7	0
1868000	MISC DF DR-OTH-CST	185361	LT CHEHALIS CSA MAINT. PREPAYMENT	SG	13,780	212	3,586	1,088	2,015	6,063	813	4	0
1868000	MISC DF DR-OTH-CST	185362	LT Currant Creek CSA Maint Prepayment	SG	12,588	193	3,276	993	1,841	5,538	742	4	0
1868000	MISC DF DR-OTH-CST	185371	LT Chehalis CSA Prepaid O&M	SG	577	9	150	46	84	254	34	0	0
1868000	MISC DF DR-OTH-CST	185372	LT Currant Creek CSA Prepaid O&M	SG	1,169	18	304	92	171	514	69	0	0
1868000 Total					**78,360**	**1,188**	**20,114**	**6,100**	**11,305**	**34,008**	**4,558**	**22**	**1,066**
1869000	MISC DF DR-OTH-NC	185334	HERMISTON SWAP	SG	2,933	45	763	231	429	1,290	173	1	0
1869000 Total					**2,933**	**45**	**763**	**231**	**429**	**1,290**	**173**	**1**	**0**
Grand Total					**85,618**	**1,258**	**21,294**	**6,455**	**11,992**	**36,011**	**4,838**	**23**	**3,746**

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Material & Supplies
Balances as of June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1511120	COAL INVNTRY-HUNTER	0	COAL INVENTORY - HUNTER	SE	43,949	639	11,032	3,304	7,023	19,055	2,882	14	0
1511120 Total					**43,949**	**639**	**11,032**	**3,304**	**7,023**	**19,055**	**2,882**	**14**	**0**
1511130	COAL INVNTRY-HTG	0	COAL INVENTORY - HUNTINGTON	SE	29,455	428	7,394	2,214	4,707	12,771	1,932	10	0
1511130 Total					**29,455**	**428**	**7,394**	**2,214**	**4,707**	**12,771**	**1,932**	**10**	**0**
1511140	COAL INVNTRY-JB	0	COAL INVENTORY - JIM BRIDGER	SE	26,713	389	6,705	2,008	4,269	11,582	1,752	9	0
1511140 Total					**26,713**	**389**	**6,705**	**2,008**	**4,269**	**11,582**	**1,752**	**9**	**0**
1511160	COAL INVNTRY-NAU	0	COAL INVENTORY - NAUGHTON	SE	17,310	252	4,345	1,301	2,766	7,505	1,135	6	0
1511160 Total					**17,310**	**252**	**4,345**	**1,301**	**2,766**	**7,505**	**1,135**	**6**	**0**
1511200	COAL INVNTRY-CHOLLA	0	COAL INVENTORY - CHOLLA	SE	14,945	217	3,752	1,124	2,388	6,480	980	5	0
1511200 Total					**14,945**	**217**	**3,752**	**1,124**	**2,388**	**6,480**	**980**	**5**	**0**
1511300	COAL INVNTRY-COLSTRI	0	COAL INVENTORY - COLSTIP	SE	1,623	24	407	122	259	704	106	1	0
1511300 Total					**1,623**	**24**	**407**	**122**	**259**	**704**	**106**	**1**	**0**
1511400	COAL INVNTRY-CRAIG	0	COAL INVENTORY - CRAIG	SE	9,531	139	2,392	716	1,523	4,132	625	3	0
1511400 Total					**9,531**	**139**	**2,392**	**716**	**1,523**	**4,132**	**625**	**3**	**0**
1511600	COAL INVNTRY-DJ	0	COAL INVENTORY - DAVE JOHNSTON	SE	9,748	142	2,447	733	1,558	4,226	639	3	0
1511600 Total					**9,748**	**142**	**2,447**	**733**	**1,558**	**4,226**	**639**	**3**	**0**
1511700	COAL INVNTRY-RG	0	COAL INVENTORY ROCK GARDEN PILE	SE	31,430	457	7,889	2,363	5,023	13,627	2,061	10	0
1511700 Total					**31,430**	**457**	**7,889**	**2,363**	**5,023**	**13,627**	**2,061**	**10**	**0**
1511900	COAL INVNTRY-HAYDEN	0	COAL INVENTORY - HAYDEN	SE	1,690	25	424	127	270	733	111	1	0
1511900 Total					**1,690**	**25**	**424**	**127**	**270**	**733**	**111**	**1**	**0**
1512180	NATURAL GAS-CLAY BAS	0	NATURAL GAS - CLAY BASIN	SE	920	13	231	69	147	399	60	0	0
1512180 Total					**920**	**13**	**231**	**69**	**147**	**399**	**60**	**0**	**0**
1514000	FUEL STK-FUEL OIL	0	FUEL STOCK COAL MINE	SE	2,291	33	575	172	366	993	150	1	0
1514000 Total					**2,291**	**33**	**575**	**172**	**366**	**993**	**150**	**1**	**0**
1514300	OIL INVNTRY-COLSTRIP	0	OIL INVENTORY - COLSTRIP	SE	107	2	27	8	17	46	7	0	0
1514300 Total					**107**	**2**	**27**	**8**	**17**	**46**	**7**	**0**	**0**
1514400	OIL INVENTORY-CRAIG	0	OIL INVENTORY - CRAIG	SE	74	1	19	6	12	32	5	0	0
1514400 Total					**74**	**1**	**19**	**6**	**12**	**32**	**5**	**0**	**0**
1514900	OIL INVENTORY-HAYDEN	0	OIL INVENTORY - HAYDEN	SE	64	1	16	5	10	28	4	0	0
1514900 Total					**64**	**1**	**16**	**5**	**10**	**28**	**4**	**0**	**0**
1541000	PLNT M&S STK CNTRL	0	MATERIAL CONTROL ADJUST	SO	(148)	(3)	(40)	(11)	(20)	(64)	(8)	(0)	0
1541000	PLNT M&S STK CNTRL	1510	JIM BRIDGER STORE ROOM	SG	25,247	388	6,570	1,992	3,692	11,108	1,489	7	0
1541000	PLNT M&S STK CNTRL	1515	DAVE JOHNSTON STORE ROOM	SG	15,329	236	3,989	1,210	2,242	6,744	904	4	0
1541000	PLNT M&S STK CNTRL	1520	WYODAK STORE ROOM	SG	6,785	104	1,766	535	992	2,985	400	2	0
1541000	PLNT M&S STK CNTRL	1525	GADSBY STORE ROOM	SG	4,396	68	1,144	347	643	1,934	259	1	0
1541000	PLNT M&S STK CNTRL	1530	CARBON STORE ROOM	SG	1	0	0	0	0	1	0	0	0
1541000	PLNT M&S STK CNTRL	1535	NAUGHTON STORE ROOM	SG	13,393	206	3,485	1,057	1,959	5,892	790	4	0

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Material & Supplies
Balances as of June 2019
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	1540	HUNTINGTON STORE ROOM	SG	19,061	293	4,960	1,504	2,788	8,386	1,124	5	0
1541000	PLNT M&S STK CNTRL	1545	HUNTER STORE ROOM	SG	25,933	399	6,749	2,047	3,793	11,410	1,529	7	0
1541000	PLNT M&S STK CNTRL	1550	BLUNDELL STORE ROOM	SG	1,235	19	321	97	181	543	73	0	0
1541000	PLNT M&S STK CNTRL	1565	CURRANT CREEK PLANT	SG	3,821	59	994	302	559	1,681	225	1	0
1541000	PLNT M&S STK CNTRL	1570	LAKESIDE PLANT	SG	6,046	93	1,573	477	884	2,660	357	2	0
1541000	PLNT M&S STK CNTRL	1580	CHEHALIS PLANT	SG	3,836	59	998	303	561	1,688	226	1	0
1541000	PLNT M&S STK CNTRL	1675	HYDRO EAST - UTAH	SG	7	0	2	1	1	3	0	0	0
1541000	PLNT M&S STK CNTRL	1680	HYDRO EAST - IDAHO	SG	3	0	1	0	0	1	0	0	0
1541000	PLNT M&S STK CNTRL	1700	LEANING JUNIPER STOREROOM	SG	444	7	116	35	65	195	26	0	0
1541000	PLNT M&S STK CNTRL	1705	GOODNOE HILLS WIND	SG	659	10	171	52	96	290	39	0	0
1541000	PLNT M&S STK CNTRL	1715	MARENGO WIND	SG	733	11	191	58	107	323	43	0	0
1541000	PLNT M&S STK CNTRL	1720	Foote Creek	SG	769	12	200	61	112	338	45	0	0
1541000	PLNT M&S STK CNTRL	1725	Glenrock/Rolling Hills	SG	1,031	16	268	81	151	454	61	0	0
1541000	PLNT M&S STK CNTRL	1730	Seven Mile Hill	SG	611	9	159	48	89	269	36	0	0
1541000	PLNT M&S STK CNTRL	1740	High Plains/McFadden	SG	538	8	140	42	79	237	32	0	0
1541000	PLNT M&S STK CNTRL	1745	Dunlap Wind Project	SG	709	11	184	56	104	312	42	0	0
1541000	PLNT M&S STK CNTRL	1799	WIND OFFICE	SG	0	0	0	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2005	CASPER STORE ROOM	WYP	586	0	0	0	586	0	0	0	0
1541000	PLNT M&S STK CNTRL	2010	BUFFALO STORE ROOM	WYP	146	0	0	0	146	0	0	0	0
1541000	PLNT M&S STK CNTRL	2015	DOUGLAS STORE ROOM	WYP	215	0	0	0	215	0	0	0	0
1541000	PLNT M&S STK CNTRL	2020	CODY STORE ROOM	WYP	631	0	0	0	631	0	0	0	0
1541000	PLNT M&S STK CNTRL	2030	WORLAND STORE ROOM	WYP	675	0	0	0	675	0	0	0	0
1541000	PLNT M&S STK CNTRL	2035	RIVERTON STORE ROOM	WYP	438	0	0	0	438	0	0	0	0
1541000	PLNT M&S STK CNTRL	2040	EVANSTON STORE ROOM	WYU	639	0	0	0	639	0	0	0	0
1541000	PLNT M&S STK CNTRL	2045	KEMMERER STORE ROOM	WYU	10	0	0	0	10	0	0	0	0
1541000	PLNT M&S STK CNTRL	2050	PINEDALE STORE ROOM	WYU	615	0	0	0	615	0	0	0	0
1541000	PLNT M&S STK CNTRL	2060	ROCK SPRINGS STORE ROOM	WYP	1,411	0	0	0	1,411	0	0	0	0
1541000	PLNT M&S STK CNTRL	2065	RAWLINS STORE ROOM	WYP	542	0	0	0	542	0	0	0	0
1541000	PLNT M&S STK CNTRL	2070	LARAMIE STORE ROOM	WYP	503	0	0	0	503	0	0	0	0
1541000	PLNT M&S STK CNTRL	2075	REXBERG STORE ROOM	IDU	1,146	0	0	0	0	0	1,146	0	0
1541000	PLNT M&S STK CNTRL	2085	SHELLY STORE ROOM	IDU	683	0	0	0	0	0	683	0	0
1541000	PLNT M&S STK CNTRL	2090	PRESTON STORE ROOM	IDU	73	0	0	0	0	0	73	0	0
1541000	PLNT M&S STK CNTRL	2095	LAVA HOT SPRINGS STORE ROOM	IDU	143	0	0	0	0	0	143	0	0
1541000	PLNT M&S STK CNTRL	2100	MONTPELIER STORE ROOM	IDU	220	0	0	0	0	0	220	0	0
1541000	PLNT M&S STK CNTRL	2110	BRIDGERLAND STORE ROOM	UT	471	0	0	0	0	471	0	0	0
1541000	PLNT M&S STK CNTRL	2205	TREMONTON STORE ROOM	UT	179	0	0	0	0	179	0	0	0
1541000	PLNT M&S STK CNTRL	2210	OGDEN STORE ROOM	UT	1,243	0	0	0	0	1,243	0	0	0
1541000	PLNT M&S STK CNTRL	2215	LAYTON STORE ROOM	UT	496	0	0	0	0	496	0	0	0

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Material & Supplies
Balances as of June 2019
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	2220	SALT LAKE METRO STORE ROOM	UT	8,394	0	0	0	0	8,394	0	0	0
1541000	PLNT M&S STK CNTRL	2230	JORDAN VALLEY STORE ROOM	UT	988	0	0	0	0	988	0	0	0
1541000	PLNT M&S STK CNTRL	2235	PARK CITY STORE ROOM	UT	1,787	0	0	0	0	1,787	0	0	0
1541000	PLNT M&S STK CNTRL	2240	TOOELE STORE ROOM	UT	405	0	0	0	0	405	0	0	0
1541000	PLNT M&S STK CNTRL	2245	WASATCH RESTORATION CENTER	UT	549	0	0	0	0	549	0	0	0
1541000	PLNT M&S STK CNTRL	2400	PLNT M&S STK CNTRL EAGLE MOUNTAIN	UT	302	0	0	0	0	302	0	0	0
1541000	PLNT M&S STK CNTRL	2405	AMERICAN FORK STORE ROOM	UT	1,442	0	0	0	0	1,442	0	0	0
1541000	PLNT M&S STK CNTRL	2410	SANTAQUIN STORE ROOM	UT	412	0	0	0	0	412	0	0	0
1541000	PLNT M&S STK CNTRL	2415	DELTA STORE ROOM	UT	334	0	0	0	0	334	0	0	0
1541000	PLNT M&S STK CNTRL	2420	VERNAL STORE ROOM	UT	659	0	0	0	0	659	0	0	0
1541000	PLNT M&S STK CNTRL	2425	PRICE STORE ROOM	UT	635	0	0	0	0	635	0	0	0
1541000	PLNT M&S STK CNTRL	2430	MOAB STORE ROOM	UT	1,005	0	0	0	0	1,005	0	0	0
1541000	PLNT M&S STK CNTRL	2435	BLANDING STORE ROOM	UT	158	0	0	0	0	158	0	0	0
1541000	PLNT M&S STK CNTRL	2445	RICHFIELD STORE ROOM	UT	108	0	0	0	0	108	0	0	0
1541000	PLNT M&S STK CNTRL	2450	CEDAR CITY STORE ROOM	UT	987	0	0	0	0	987	0	0	0
1541000	PLNT M&S STK CNTRL	2455	MILFORD STORE ROOM	UT	354	0	0	0	0	354	0	0	0
1541000	PLNT M&S STK CNTRL	2460	WASHINGTON STORE ROOM	UT	580	0	0	0	0	580	0	0	0
1541000	PLNT M&S STK CNTRL	2620	WALLA WALLA STORE ROOM	WA	1,472	0	0	1,472	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2630	YAKIMA STORE ROOM	WA	454	0	0	454	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2635	ENTERPRISE STORE ROOM	OR	188	0	188	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2640	PENDLETON STORE ROOM	OR	924	0	924	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2650	HOOD RIVER STORE ROOM	OR	491	0	491	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2655	PORTLAND METRO - STORE ROOM	OR	11,461	0	11,461	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2660	ASTORIA STORE ROOM	OR	1,160	0	1,160	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2665	MADRAS STORE ROOM	OR	128	0	128	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2670	PRINEVILLE STORE ROOM	OR	50	0	50	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2675	BEND STORE ROOM	OR	1,945	0	1,945	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2805	ALBANY STORE ROOM	OR	198	0	198	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2810	LINCOLN CITY STORE ROOM	OR	233	0	233	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2830	ROSEBURG STORE ROOM	OR	2,842	0	2,842	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2835	COOS BAY STORE ROOM	OR	858	0	858	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2840	GRANTS PASS STORE ROOM	OR	961	0	961	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2845	MEDFORD STORE ROOM	OR	937	0	937	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2850	KLAMATH FALLS STORE ROOM	OR	2,499	0	2,499	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2855	LAKEVIEW STORE ROOM	OR	123	0	123	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2860	ALTURAS STORE ROOM	CA	76	76	0	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2865	MT SHASTA STORE ROOM	CA	256	256	0	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	2870	YREKA STORE ROOM	CA	1,073	1,073	0	0	0	0	0	0	0

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Material & Supplies
Balances as of June 2019
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	2875	CRESENT CITY STORE ROOM	CA	455	455	0	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	5005	TREMONTON STORE ROOM	SO	144	3	39	11	20	63	8	0	0
1541000	PLNT M&S STK CNTRL	5110	MATERIAL PACKAGING CENTER - WEST	OR	0	0	0	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	5115	DEMC - SLC	SNPD	59	2	16	4	6	28	3	0	0
1541000	PLNT M&S STK CNTRL	5120	DEMC - MEDFORD	OR	72	0	72	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	5125	DEMC - OREGON	OR	9,553	0	9,553	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	5130	MEDFORD HUB	OR	7,145	0	7,145	0	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	5135	YAKIMA HUB	WA	7,039	0	0	7,039	0	0	0	0	0
1541000	PLNT M&S STK CNTRL	5140	PRESTON HUB	IDU	3,790	0	0	0	0	0	3,790	0	0
1541000	PLNT M&S STK CNTRL	5150	RICHFIELD HUB	UT	4,071	0	0	0	0	4,071	0	0	0
1541000	PLNT M&S STK CNTRL	5155	CASPER HUB	WYP	5,575	0	0	0	5,575	0	0	0	0
1541000	PLNT M&S STK CNTRL	5160	SALT LAKE METRO HUB	UT	24,041	0	0	0	0	24,041	0	0	0
1541000	PLNT M&S STK CNTRL	5200	UTAH TRANSPORTATION BUILDING	SNPD	22	1	6	1	2	11	1	0	0
1541000	PLNT M&S STK CNTRL	5300	METER TEST WAREHOUSE	UT	3	0	0	0	0	3	0	0	0
1541000 Total					**250,899**	**3,869**	**75,772**	**19,276**	**31,093**	**107,093**	**13,760**	**37**	**0**
1541500	OTHER M&S	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SO	377	8	103	29	51	164	22	0	0
1541500 Total					**377**	**8**	**103**	**29**	**51**	**164**	**22**	**0**	**0**
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SG	1,362	21	354	108	199	599	80	0	0
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SO	3	0	1	0	0	1	0	0	0
1541900 Total					**1,365**	**21**	**355**	**108**	**200**	**601**	**81**	**0**	**0**
1549900	CR-OBSOL&SURPL INV	102930	SB Asset # 120930	SO	(27)	(1)	(7)	(2)	(4)	(12)	(2)	(0)	0
1549900	CR-OBSOL&SURPL INV	120930	INVENTORY RESERVE POWER SUPPLY	SG	(1,068)	(16)	(278)	(84)	(156)	(470)	(63)	(0)	0
1549900	CR-OBSOL&SURPL INV	120930	INVENTORY RESERVE POWER SUPPLY	SO	(12)	(0)	(3)	(1)	(2)	(5)	(1)	(0)	0
1549900	CR-OBSOL&SURPL INV	120932	Inventory Reserve - RMP (T&D)	SNPD	(904)	(33)	(242)	(56)	(93)	(435)	(46)	0	0
1549900	CR-OBSOL&SURPL INV	120933	Inventory Reserve - PP (T&D)	SNPD	(919)	(33)	(246)	(56)	(94)	(442)	(47)	0	0
1549900 Total					**(2,931)**	**(83)**	**(777)**	**(199)**	**(348)**	**(1,365)**	**(158)**	**(0)**	**0**
2531600	WORK CAP DEP-UAMPS	289920	WORKING CAPITAL DEPOSIT - UAMPS	SE	(2,479)	(36)	(622)	(186)	(396)	(1,075)	(163)	(1)	0
2531600 Total					**(2,479)**	**(36)**	**(622)**	**(186)**	**(396)**	**(1,075)**	**(163)**	**(1)**	**0**
2531700	WORKG CAP DEP-DG&T	289921	OTH DEF CR - WORKING CAPITAL DEPOS-DG&T	SE	(2,622)	(38)	(658)	(197)	(419)	(1,137)	(172)	(1)	0
2531700 Total					**(2,622)**	**(38)**	**(658)**	**(197)**	**(419)**	**(1,137)**	**(172)**	**(1)**	**0**
2531800	WCD-PROVO-PLNT M&S	289922	OTH DEF CR - WCD - PROVO - PLANT M&S	SG	(273)	(4)	(71)	(22)	(40)	(120)	(16)	(0)	0
2531800 Total					**(273)**	**(4)**	**(71)**	**(22)**	**(40)**	**(120)**	**(16)**	**(0)**	**0**
Grand Total					**434,188**	**6,498**	**121,758**	**33,081**	**60,478**	**186,473**	**25,803**	**97**	**0**

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Cash Working Capital
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1430000	OTHER ACCTS REC	0	OTHER ACCOUNTS RECEIVABLE	SO	3	0	1	0	0	1	0	0	0
1430000 Total					**3**	**0**	**1**	**0**	**0**	**1**	**0**	**0**	**0**
1431000	EMP ACCOUNTS REC	0	EMPLOYEE RECEIVABLES	SO	4,636	103	1,262	357	630	2,017	266	1	0
1431000 Total					**4,636**	**103**	**1,262**	**357**	**630**	**2,017**	**266**	**1**	**0**
1431500	INC TAXES RECEIVABLE	0	INCOME TAXES RECEIVABLE	SO	-70	-2	-19	-5	-10	-31	-4	0	0
1431500	INC TAXES RECEIVABLE	116133	InterCo State Tax Rec-(Even Years)- MEHC	SO	186	4	51	14	25	81	11	0	0
1431500	INC TAXES RECEIVABLE	116134	InterCo State Tax Rec -(Odd Years)- MEHC	SO	-116	-3	-32	-9	-16	-50	-7	0	0
1431500 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
1433000	JOINT OWNER REC	0	JOINT OWNER RECEIVABLE	SO	16,683	372	4,540	1,284	2,268	7,257	957	3	0
1433000 Total					**16,683**	**372**	**4,540**	**1,284**	**2,268**	**7,257**	**957**	**3**	**0**
1436000	OTH ACCT REC	0	OTHER ACCOUNTS RECEIVABLE	SO	20,196	451	5,497	1,555	2,746	8,785	1,159	4	0
1436000 Total					**20,196**	**451**	**5,497**	**1,555**	**2,746**	**8,785**	**1,159**	**4**	**0**
1437000	CSS OAR BILLINGS	0	CSS OAR BILLINGS	SO	5,814	130	1,582	448	791	2,529	334	1	0
1437000 Total					**5,814**	**130**	**1,582**	**448**	**791**	**2,529**	**334**	**1**	**0**
1437100	CSS OAR BILLINGS-WOR	0	OTHER ACCT REC CCS	SO	-2,476	-55	-674	-191	-337	-1,077	-142	-1	0
1437100 Total					**-2,476**	**-55**	**-674**	**-191**	**-337**	**-1,077**	**-142**	**-1**	**0**
2300000	ASSET RETIREMENT OBL	284915	ARO LIAB - DEER CREEK MINE RECLAMATION	OTHER	-8,268	0	0	0	0	0	0	0	-8,268
2300000 Total					**-8,268**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-8,268**
2320000	ACCOUNTS PAYABLE	210460	JOINT OWNER RECEIVABLES - CREDIT	SE	-1,753	-25	-440	-132	-280	-760	-115	-1	0
2320000	ACCOUNTS PAYABLE	211108	UNION DUES/CONTRIBUTIONS WITHHOLDING	SO	0	0	0	0	0	0	0	0	0
2320000	ACCOUNTS PAYABLE	211112	UNITED FUND/CHARITABLE WITHHOLDINGS	SO	0	0	0	0	0	0	0	0	0
2320000	ACCOUNTS PAYABLE	211115	Allstate Voluntary Benefit Withholdings	SO	0	0	0	0	0	0	0	0	0
2320000	ACCOUNTS PAYABLE	211116	DEPENDENT SUPPORT/LEVY WITHHOLDINGS	SO	-14	0	-4	-1	-2	-6	-1	0	0
2320000	ACCOUNTS PAYABLE	215077	K-PLUS EMPLOYER CONTRIBUTIONS - ENHANCED	SO	-436	-10	-119	-34	-59	-190	-25	0	0
2320000	ACCOUNTS PAYABLE	215078	K-Plus Employer Contributions - Fixed	SO	-1,249	-28	-340	-96	-170	-543	-72	0	0
2320000	ACCOUNTS PAYABLE	215080	METLIFE MEDICAL INSURANCE	SO	-3,984	-89	-1,084	-307	-542	-1,733	-229	-1	0
2320000	ACCOUNTS PAYABLE	215082	METLIFE DENTAL INSURANCE	SO	-60	-1	-16	-5	-8	-26	-3	0	0
2320000	ACCOUNTS PAYABLE	215084	METLIFE VISION INSURANCE	SO	-16	0	-4	-1	-2	-7	-1	0	0
2320000	ACCOUNTS PAYABLE	215085	Western Utilities Dental Payable	SO	-11	0	-3	-1	-1	-5	-1	0	0
2320000	ACCOUNTS PAYABLE	215086	Western Utilities Vision Payable	SO	-1	0	0	0	0	0	0	0	0
2320000	ACCOUNTS PAYABLE	215088	UWUA Health & Welfare Payable	SO	-4	0	-1	0	-1	-2	0	0	0
2320000	ACCOUNTS PAYABLE	215095	HMO HEALTH PLAN	SO	-12	0	-3	-1	-2	-5	-1	0	0
2320000	ACCOUNTS PAYABLE	215112	Minnesota Life Insurance	SO	-19	0	-5	-1	-3	-8	-1	0	0
2320000	ACCOUNTS PAYABLE	215116	IBEW 57 MEDICAL INSURANCE	SO	-50	-1	-14	-4	-7	-22	-3	0	0
2320000	ACCOUNTS PAYABLE	215350	"IBEW 57 HEALTH REIMBURSEMENT, CURRENT Y	SO	-5	0	-1	0	-1	-2	0	0	0

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Cash Working Capital
Twelve Months Ending - June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2320000	ACCOUNTS PAYABLE	215351	"IBEW 57 DEPENDENT CARE REIMBURSEMENT, C	SO	0	0	0	0	0	0	0	0	0
2320000	ACCOUNTS PAYABLE	215356	"HEALTH REIMBURSEMENT, CURRENT YEAR"	SO	-9	0	-2	-1	-1	-4	0	0	0
2320000	ACCOUNTS PAYABLE	215357	"DEPENDENT CARE REIMBURSEMENT, CURRENT Y	SO	13	0	4	1	2	6	1	0	0
2320000	ACCOUNTS PAYABLE	215425	OR DOE Cool School Program	OTHER	-17	0	0	0	0	0	0	0	-17
2320000	ACCOUNTS PAYABLE	215439	Cal ISO Trans Payable	SG	-2,053	-32	-534	-162	-300	-903	-121	-1	0
2320000	ACCOUNTS PAYABLE	235230	ACCRUAL - ROYALTIES	SE	-61	-1	-15	-5	-10	-26	-4	0	0
2320000	ACCOUNTS PAYABLE	235599	Safety Award	SO	-1,141	-25	-311	-88	-155	-496	-65	0	0
2320000	ACCOUNTS PAYABLE	240330	PROVISION FOR WORKERS' COMPENSATION	SO	-130	-3	-35	-10	-18	-56	-7	0	0
2320000 Total					**-11,012**	**-217**	**-2,929**	**-847**	**-1,559**	**-4,790**	**-649**	**-3**	**-17**
2533000	O DEF CR-MISC PPL	289517	TRAPPER MINE FINAL RECLAMATION	SE	-6,513	-95	-1,635	-490	-1,041	-2,824	-427	-2	0
2533000 Total					**-6,513**	**-95**	**-1,635**	**-490**	**-1,041**	**-2,824**	**-427**	**-2**	**0**
2541050	FAS143 ARO REG LIAB	00111920	REG LIAB-ARO/REGDIFF DEER CREEK MINE REC	SE	-20	0	-5	-1	-3	-9	-1	0	0
2541050	FAS143 ARO REG LIAB	111920	REG LIAB-ARO/REGDIFF DEER CREEK MINE REC	SE	20	0	5	1	3	9	1	0	0
2541050 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Grand Total					**19,064**	**689**	**7,644**	**2,116**	**3,499**	**11,898**	**1,498**	**4**	**-8,285**

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Miscellaneous Rate Base
Balances as of June 2019
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	2,224	37,656	11,420	21,164	63,666	8,534	41	0
1140000	EL PLT ACQUIST ADJ	1140000	ELECTRIC PLANT ACQUISITION ADJUSTMENTS	UT	11,764	0	0	0	0	11,764	0	0	0
1140000 Total					**156,468**	**2,224**	**37,656**	**11,420**	**21,164**	**75,430**	**8,534**	**41**	**0**
1150000	Ac Prov El Pt Acq Ad	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	SG	-128,417	-1,973	-33,418	-10,135	-18,781	-56,500	-7,573	-36	0
1150000	Ac Prov El Pt Acq Ad	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	UT	-1,294	0	0	0	0	-1,294	0	0	0
1150000 Total					**-129,712**	**-1,973**	**-33,418**	**-10,135**	**-18,781**	**-57,795**	**-7,573**	**-36**	**0**
1281000	Oth Special Funds-Pn	0	Other special funds - Pensions	SO	2,485	55	676	191	338	1,081	143	1	0
1281000 Total					**2,485**	**55**	**676**	**191**	**338**	**1,081**	**143**	**1**	**0**
1651000	PREPAY-INSURANCE	132008	PREPAID INSURANCE - PUBLIC LIABILITY & P	SO	341	8	93	26	46	148	20	0	0
1651000	PREPAY-INSURANCE	132012	PREPAID INSURANCE - ALLPURPOSE INSURANCE	SO	1,023	23	278	79	139	445	59	0	0
1651000	PREPAY-INSURANCE	132016	PREPAID INS-MINORITY OWNED PLANTS	SO	677	15	184	52	92	294	39	0	0
1651000	PREPAY-INSURANCE	132045	PREPAID WORKERS COMPENSATION	SO	416	9	113	32	57	181	24	0	0
1651000	PREPAY-INSURANCE	132055	PREPAID EMPLOYEE BENEFIT COSTS	SO	75	2	20	6	10	33	4	0	0
1651000 Total					**2,532**	**56**	**689**	**195**	**344**	**1,101**	**145**	**1**	**0**
1652000	PREPAY-TAXES	132109	UTE-PREPAID POSSESSORY INTEREST	GPS	20	0	6	2	3	9	1	0	0
1652000	PREPAY-TAXES	132110	SHO-BAN-PREPAID POSSESSORY INTEREST	GPS	136	3	37	10	18	59	8	0	0
1652000	PREPAY-TAXES	132111	Goshute - Prepaid Possessory Interest	GPS	15	0	4	1	2	6	1	0	0
1652000 Total					**171**	**4**	**46**	**13**	**23**	**74**	**10**	**0**	**0**
1652100	PREPAY - OTHER	132097	Prepaid CA GHG Cap & Trade Allowances	OTHER	10,731	0	0	0	0	0	0	0	10,731
1652100	PREPAY - OTHER	132098	Prepaid - CA GHG Wholesale	OTHER	4,892	0	0	0	0	0	0	0	4,892
1652100	PREPAY - OTHER	132310	PREPAID RATING AGNCY	SO	73	2	20	6	10	32	4	0	0
1652100	PREPAY - OTHER	132608	Prepaid - Records Management Costs	SG	66	1	17	5	10	29	4	0	0
1652100	PREPAY - OTHER	132620	PREPAYMENTS - WATER RIGHTS LEASE	SG	639	10	166	50	93	281	38	0	0
1652100	PREPAY - OTHER	132621	Prepayments - Water Rights (Ferron Canal	SG	223	3	58	18	33	98	13	0	0
1652100	PREPAY - OTHER	132622	Prepayments - Water Rights (Hntgtn-Clev)	SG	264	4	69	21	39	116	16	0	0
1652100	PREPAY - OTHER	132650	PREPAID DUES	SO	3,186	71	867	245	433	1,386	183	1	0
1652100	PREPAY - OTHER	132700	PREPAID RENT	GPS	11	0	3	1	1	5	1	0	0
1652100	PREPAY - OTHER	132740	PREPAID O&M WIND	SG	48	1	12	4	7	21	3	0	0
1652100	PREPAY - OTHER	132755	Prepaid Aircraft Maintenance Costs	SG	35	1	9	3	5	16	2	0	0
1652100	PREPAY - OTHER	132831	PREPAID BPA TRANSM - WINE COUNTRY	SG	984	15	256	78	144	433	58	0	0
1652100	PREPAY - OTHER	132900	PREPAYMENTS - OTHER	SE	72	1	18	5	12	31	5	0	0
1652100	PREPAY - OTHER	132900	PREPAYMENTS - OTHER	SO	676	15	184	52	92	294	39	0	0
1652100	PREPAY - OTHER	132901	PRE FEES - OREGON PUB UTIL COMMISSION	OR	3,031	0	3,031	0	0	0	0	0	0
1652100	PREPAY - OTHER	132903	PREP FEES-UTAH PUBLIC SERVICE COMMISSION	UT	6,209	0	0	0	0	6,209	0	0	0
1652100	PREPAY - OTHER	132904	PREP FEES-IDAHO PUB UTIL COMMISSION	IDU	362	0	0	0	0	0	362	0	0
1652100	PREPAY - OTHER	132910	Prepayments - Hardware & Software	SO	12,338	275	3,358	950	1,678	5,367	708	3	0
1652100	PREPAY - OTHER	132998	PREPAID INSURANCE	SE	-68	-1	-17	-5	-11	-30	-4	0	0
1652100	PREPAY - OTHER	132999	PREPAY - RECLASS TO LT	SO	-499	-11	-136	-38	-68	-217	-29	0	0
1652100	PREPAY - OTHER	134000	L/T PREPAY RECLASS	SO	567	13	154	44	77	247	33	0	0
1652100 Total					**43,838**	**400**	**8,070**	**1,437**	**2,554**	**14,317**	**1,434**	**4**	**15,623**
2281000	ACC PROV-PROP INS	288712	Reg Liab - OR Property Insurance Reserve	OR	11,606	0	11,606	0	0	0	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2281000	ACC PROV-PROP INS	288714	Reg Liab - ID Property Insurance Reserve	IDU	-833	0	0	0	0	0	-833	0	0
2281000	ACC PROV-PROP INS	288715	Reg Liab - UT Property Insurance Reserve	UT	-7,177	0	0	0	0	-7,177	0	0	0
2281000	ACC PROV-PROP INS	288716	Reg Liab - WY Property Insurance Reserve	WYP	-946	0	0	0	-946	0	0	0	0
2281000	ACC PROV-PROP INS	288749	RegL - Insurance Reserves - Reclass	OTHER	-11,606	0	0	0	0	0	0	0	-11,606
2281000 Total					**-8,956**	**0**	**11,606**	**0**	**-946**	**-7,177**	**-833**	**0**	**-11,606**
2282100	ACC PRV IN & DAMAG	280311	ACC. PROV. I & D - EXCL. AUTO	SO	-16,281	-363	-4,431	-1,253	-2,214	-7,082	-934	-3	0
2282100 Total					**-16,281**	**-363**	**-4,431**	**-1,253**	**-2,214**	**-7,082**	**-934**	**-3**	**0**
2282400	ACCUM PRV FR I&D-OR	288700	Reg Liab - OR Injuries & Damages Reserve	OR	-8,768	0	-8,768	0	0	0	0	0	0
2282400 Total					**-8,768**	**0**	**-8,768**	**0**	**0**	**0**	**0**	**0**	**0**
2283000	PEN/BENFT-SICK	280349	SUPPL. PENSION BENEFITS (RETIRE ALLOW)	SO	-1,651	-37	-449	-127	-224	-718	-95	0	0
2283000 Total					**-1,651**	**-37**	**-449**	**-127**	**-224**	**-718**	**-95**	**0**	**0**
2283400	POST-RETIREMENT BEN	280329	FAS 106-Contra Liability-Medicare Subsid	SO	22,389	500	6,093	1,724	3,044	9,739	1,285	5	0
2283400	POST-RETIREMENT BEN	280440	FAS 158 PR Liab Medicare Sub (Non-Dedct)	SO	-5,429	-121	-1,478	-418	-738	-2,362	-312	-1	0
2283400	POST-RETIREMENT BEN	280454	FAS 158 PR Liab Reg Medicare (Non-Dedct)	SO	5,429	121	1,478	418	738	2,362	312	1	0
2283400	POST-RETIREMENT BEN	280456	FAS 106-Contra Liab-Med.Sub.Claims	SO	-16,960	-378	-4,616	-1,306	-2,306	-7,377	-973	-3	0
2283400	POST-RETIREMENT BEN	280457	FAS 158 - CONTRA LIA - Reg Medicare	SO	-5,429	-121	-1,478	-418	-738	-2,362	-312	-1	0
2283400 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2283500	PENSIONS	280350	Pension - Local 57	SO	-572	-13	-156	-44	-78	-249	-33	0	0
2283500	PENSIONS	280355	FAS 158 Pension Liability	SO	-98,349	-2,195	-26,766	-7,571	-13,372	-42,781	-5,644	-20	0
2283500	PENSIONS	280365	FAS 158 Pension Liab-Rcls to Current	SO	572	13	156	44	78	249	33	0	0
2283500 Total					**-98,349**	**-2,195**	**-26,766**	**-7,571**	**-13,372**	**-42,781**	**-5,644**	**-20**	**0**
2284100	AC MIS OP PR-OTHER	289320	CHEHALIS WA EFSEC C02 MITIGATION OBLIG	SG	-512	-8	-133	-40	-75	-225	-30	0	0
2284100 Total					**-512**	**-8**	**-133**	**-40**	**-75**	**-225**	**-30**	**0**	**0**
2300000	ASSET RETIREMENT OBL	284918	ARO LIAB - TROJAN NUCLEAR PLANT	TROJD	-2,744	-42	-709	-215	-408	-1,204	-165	-1	0
2300000 Total					**-2,744**	**-42**	**-709**	**-215**	**-408**	**-1,204**	**-165**	**-1**	**0**
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	CA	-41	-41	0	0	0	0	0	0	0
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	IDU	-17	0	0	0	0	0	-17	0	0
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	OR	-150	0	-150	0	0	0	0	0	0
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	UT	-42	0	0	0	0	-42	0	0	0
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	WA	-18	0	0	-18	0	0	0	0	0
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	WYP	-34	0	0	0	-34	0	0	0	0
2530000 Total					**-302**	**-41**	**-150**	**-18**	**-34**	**-42**	**-17**	**0**	**0**
2533500	OTH DEF CR-PEN & BEN	280370	PENSION LIAB-UMWA WITHDRAWAL OBLIG	SE	-115,119	-1,674	-28,897	-8,654	-18,396	-49,911	-7,549	-37	0
2533500 Total					**-115,119**	**-1,674**	**-28,897**	**-8,654**	**-18,396**	**-49,911**	**-7,549**	**-37**	**0**
2539900	OTH DEF CR - OTHER	0	Fossil Rock Fuels Entries	SE	-5,006	-73	-1,257	-376	-800	-2,171	-328	-2	0
2539900	OTH DEF CR - OTHER	230155	EMPLOYEE HOUSING SECURITY DEPOSITS	CA	-20	-20	0	0	0	0	0	0	0
2539900	OTH DEF CR - OTHER	288608	Envir Liab - Colstrip Pond	SO	-9,857	-220	-2,683	-759	-1,340	-4,288	-566	-2	0
2539900	OTH DEF CR - OTHER	288609	Envir Liab - Cholla Ash-Fly Ash Pond	SO	-5,129	-114	-1,396	-395	-697	-2,231	-294	-1	0
2539900	OTH DEF CR - OTHER	288614	Envir Liab - American Barrel (UT)	SO	-1,282	-29	-349	-99	-174	-558	-74	0	0
2539900	OTH DEF CR - OTHER	288616	Envir Liab - Astoria/Unocal (Downtown)	SO	-690	-15	-188	-53	-94	-300	-40	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2539900	OTH DEF CR - OTHER	288618	Envir Liab - Astoria Young's Bay	SO	-285	-6	-77	-22	-39	-124	-16	0	0
2539900	OTH DEF CR - OTHER	288620	Envir Liab - Big Fork Hydro Plant (MT)	SO	-249	-6	-68	-19	-34	-108	-14	0	0
2539900	OTH DEF CR - OTHER	288621	Envir Liab - Bors Property	SO	-10	0	-3	-1	-1	-4	-1	0	0
2539900	OTH DEF CR - OTHER	288622	Envir Liab - Bridger Coal Fuel Oil Spill	SO	-682	-15	-186	-53	-93	-297	-39	0	0
2539900	OTH DEF CR - OTHER	288623	Envir Liab - Bridger Plant-FGD Pond 1	SO	-2,696	-60	-734	-208	-367	-1,173	-155	-1	0
2539900	OTH DEF CR - OTHER	288624	Envir Liab - Bridger FGD Pond 1 Closure	SO	-850	-19	-231	-65	-116	-370	-49	0	0
2539900	OTH DEF CR - OTHER	288625	Envir Liab - Bridger Plant-FGD Pond 2	SO	-1,520	-34	-414	-117	-207	-661	-87	0	0
2539900	OTH DEF CR - OTHER	288626	Envir Liab - Bridger Plant Oil Spills	SO	-794	-18	-216	-61	-108	-345	-46	0	0
2539900	OTH DEF CR - OTHER	288627	Envir Liab - Carbon Ash Spill	SO	-4,170	-93	-1,135	-321	-567	-1,814	-239	-1	0
2539900	OTH DEF CR - OTHER	288628	Envir Liab - Cedar Steam Plant (UT)	SO	-8	0	-2	-1	-1	-3	0	0	0
2539900	OTH DEF CR - OTHER	288630	Envir Liab - Dave Johnston Oil Spill	SO	-729	-16	-198	-56	-99	-317	-42	0	0
2539900	OTH DEF CR - OTHER	288632	Envir Liab - Eugene MGP (50% PCRP)	SO	-309	-7	-84	-24	-42	-134	-18	0	0
2539900	OTH DEF CR - OTHER	288633	Envir Liab - Dave Johnston-Pond 4A & 4B	SO	-2,266	-51	-617	-174	-308	-986	-130	0	0
2539900	OTH DEF CR - OTHER	288634	Envir Liab - Everett MGP (2/3 PCRP)	SO	-240	-5	-65	-18	-33	-104	-14	0	0
2539900	OTH DEF CR - OTHER	288636	Envir Liab - Hunter Fuel Oil Spills	SO	-156	-3	-42	-12	-21	-68	-9	0	0
2539900	OTH DEF CR - OTHER	288638	Envir Liab - Huntington Ash Landfill	SO	-2,564	-57	-698	-197	-349	-1,115	-147	-1	0
2539900	OTH DEF CR - OTHER	288639	Envir Liab - Hayden Ash Landfill	SO	-606	-14	-165	-47	-82	-264	-35	0	0
2539900	OTH DEF CR - OTHER	288640	Envir Liab - Idaho Falls Pole Yard	SO	-1,956	-44	-532	-151	-266	-851	-112	0	0
2539900	OTH DEF CR - OTHER	288642	Envir Liab - Jordan Plant Substation	SO	-165	-4	-45	-13	-22	-72	-9	0	0
2539900	OTH DEF CR - OTHER	288645	Envir Liab - Naughton Plant-FGD Pond 1	SO	-433	-10	-118	-33	-59	-188	-25	0	0
2539900	OTH DEF CR - OTHER	288648	Envir Liab - Naughton FGD Pond Closure	SO	-147	-3	-40	-11	-20	-64	-8	0	0
2539900	OTH DEF CR - OTHER	288650	Envir Liab - Ogden MGP	SO	-513	-11	-140	-39	-70	-223	-29	0	0
2539900	OTH DEF CR - OTHER	288651	Envir Liab - Ririe Substation	SO	-41	-1	-11	-3	-6	-18	-2	0	0
2539900	OTH DEF CR - OTHER	288652	Envir Liab - Olympia MGP	SO	-39	-1	-11	-3	-5	-17	-2	0	0
2539900	OTH DEF CR - OTHER	288653	Envir Liab - Naughton Plant-FGD Pond 2	SO	-1,298	-29	-353	-100	-177	-565	-75	0	0
2539900	OTH DEF CR - OTHER	288655	Envir Liab - Hunter Plant-Ash Landfill	SO	-2,206	-49	-600	-170	-300	-959	-127	0	0
2539900	OTH DEF CR - OTHER	288656	Envir Liab - Portland Harbor Srce Cntrl	SO	-13,278	-296	-3,614	-1,022	-1,805	-5,776	-762	-3	0
2539900	OTH DEF CR - OTHER	288660	Envir Liab - Silver Bell/Telluride	SO	-1,485	-33	-404	-114	-202	-646	-85	0	0
2539900	OTH DEF CR - OTHER	288664	Envir Liab - Tacoma A St. (25% PCRP)	SO	-103	-2	-28	-8	-14	-45	-6	0	0
2539900	OTH DEF CR - OTHER	288666	Envir Liab - Utah Metals East	SO	-368	-8	-100	-28	-50	-160	-21	0	0
2539900	OTH DEF CR - OTHER	288668	Envir Liab - Wyodak Fuel Oil Spill	SO	-97	-2	-26	-7	-13	-42	-6	0	0
2539900	OTH DEF CR - OTHER	288676	Envir Liab - Naughton South Ash Pond	SO	-876	-20	-238	-67	-119	-381	-50	0	0
2539900	OTH DEF CR - OTHER	289051	DEFERRED RENT REVENUE AMORT OIL & GAS LE	SG	-321	-5	-83	-25	-47	-141	-19	0	0
2539900	OTH DEF CR - OTHER	289341	Accrued Royalties-Reg Rcvry-Noncurrent	SE	-7,538	-110	-1,892	-567	-1,205	-3,268	-494	-2	0
2539900	OTH DEF CR - OTHER	289523	Govt Coal Lease Bonus Payment Liability	SE	5,006	73	1,257	376	800	2,171	328	2	0
2539900	OTH DEF CR - OTHER	289540	Westmoreland Kemmerer Payable-NonCurr	SG	-10,990	-169	-2,860	-867	-1,607	-4,835	-648	-3	0
2539900	OTH DEF CR - OTHER	289913	MCI - F.O.G. WIRE LEASE	SG	-1,766	-27	-460	-139	-258	-777	-104	-1	0
2539900	OTH DEF CR - OTHER	289914	AMERICAN ELECTRIC POWER CRP	SG	-2,110	-32	-549	-167	-309	-928	-124	-1	0
2539900	OTH DEF CR - OTHER	289925	TRANSM CONST SECURITY DEPOSITS	SG	-8,491	-130	-2,210	-670	-1,242	-3,736	-501	-2	0
2539900	OTH DEF CR - OTHER	289955	Accrued Right-of-Way Obligations	SG	-2,631	-40	-685	-208	-385	-1,158	-155	-1	0
2539900 Total					**-91,965**	**-1,831**	**-24,550**	**-7,116**	**-12,952**	**-40,115**	**-5,380**	**-22**	**0**

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2540000	REGULATORY LIAB	186149	Reg Asset - DSM - UT - Balance Reclass	OTHER	12,459	0	0	0	0	0	0	0	12,459
2540000	REGULATORY LIAB	231010	Reg Liab Current - Blue Sky	OTHER	-13,504	0	0	0	0	0	0	0	-13,504
2540000	REGULATORY LIAB	231020	Reg Liab Current - DSM	OTHER	-20,131	0	0	0	0	0	0	0	-20,131
2540000	REGULATORY LIAB	231045	Reg Liab Current - GHG Allowances	OTHER	-4,462	0	0	0	0	0	0	0	-4,462
2540000	REGULATORY LIAB	231050	Reg Liab Current - Def Net Power Costs	OTHER	-11,347	0	0	0	0	0	0	0	-11,347
2540000	REGULATORY LIAB	231060	Reg Liab Current - BPA Balancing Accts	OTHER	-3,252	0	0	0	0	0	0	0	-3,252
2540000	REGULATORY LIAB	231090	Reg Liab Current - Solar Feed-In	OTHER	-19,826	0	0	0	0	0	0	0	-19,826
2540000	REGULATORY LIAB	231100	Reg Liab Current - Other	OTHER	-9,227	0	0	0	0	0	0	0	-9,227
2540000	REGULATORY LIAB	288001	Reg Liab - Excess Def Inc Taxes - CA	CA	-1,109	-1,109	0	0	0	0	0	0	0
2540000	REGULATORY LIAB	288002	Reg Liab - Excess Def Inc Taxes - ID	IDU	-1,553	0	0	0	0	0	-1,553	0	0
2540000	REGULATORY LIAB	288003	Reg Liab - Excess Def Inc Taxes - OR	OR	-15,769	0	-15,769	0	0	0	0	0	0
2540000	REGULATORY LIAB	288005	Reg Liab - Excess Def Inc Taxes - WA	WA	-1,327	0	0	-1,327	0	0	0	0	0
2540000	REGULATORY LIAB	288006	Reg Liab - Excess Def Inc Taxes - WY	WYU	-11,956	0	0	0	-11,956	0	0	0	0
2540000	REGULATORY LIAB	288007	Reg Liab - Excess Def Inc Taxes - FERC	FERC	-18	0	0	0	0	0	0	-18	0
2540000	REGULATORY LIAB	288108	FAS 109 - WA Flowthrough	WA	-756	0	0	-756	0	0	0	0	0
2540000	REGULATORY LIAB	288114	REG LIABILITY - OR GAIN-SALE EPUD ASSETS	OTHER	1	0	0	0	0	0	0	0	1
2540000	REGULATORY LIAB	288159	RegL - Blue Sky - Recl to Curr	OTHER	13,504	0	0	0	0	0	0	0	13,504
2540000	REGULATORY LIAB	288161	RL-Energy Savings Assistance (ESA)-CA	OTHER	-505	0	0	0	0	0	0	0	-505
2540000	REGULATORY LIAB	288165	Reg Liab - OR Enrgy	OTHER	-2,867	0	0	0	0	0	0	0	-2,867
2540000	REGULATORY LIAB	288174	RegL - OR Asset Sale Gain-Balance Recl	OTHER	-703	0	0	0	0	0	0	0	-703
2540000	REGULATORY LIAB	288231	Reg Liab - OR 2013 FERC Rate True-Up	OTHER	-3,515	0	0	0	0	0	0	0	-3,515
2540000	REGULATORY LIAB	288232	Reg Liab - OR 2017 FERC Rate True-Up	OTHER	-29,794	0	0	0	0	0	0	0	-29,794
2540000	REGULATORY LIAB	288240	Reg Liab - WA PCAM - CY 2016	OTHER	-7,832	0	0	0	0	0	0	0	-7,832
2540000	REGULATORY LIAB	288243	Reg Liability - WA PCAM CY2018	OTHER	-6,455	0	0	0	0	0	0	0	-6,455
2540000	REGULATORY LIAB	288245	Contra Reg Liability - WA PCAM CY2018	OTHER	-323	0	0	0	0	0	0	0	-323
2540000	REGULATORY LIAB	288246	Reg Liability - WA PCAM CY2019	OTHER	-256	0	0	0	0	0	0	0	-256
2540000	REGULATORY LIAB	288247	Contra Reg Liability - WA PCAM CY2019	OTHER	-13	0	0	0	0	0	0	0	-13
2540000	REGULATORY LIAB	288281	Reg Liab-Excess Income Tax Deferral-CA	OTHER	-4,833	0	0	0	0	0	0	0	-4,833
2540000	REGULATORY LIAB	288282	Reg Liab-Excess Income Tax Deferral-ID	OTHER	-1,093	0	0	0	0	0	0	0	-1,093
2540000	REGULATORY LIAB	288283	Reg Liab-Excess Income Tax Deferral-OR	OTHER	-50,091	0	0	0	0	0	0	0	-50,091
2540000	REGULATORY LIAB	288284	Reg Liab-Excess Income Tax Deferral-UT	OTHER	-3,011	0	0	0	0	0	0	0	-3,011
2540000	REGULATORY LIAB	288285	Reg Liab-Excess Income Tax Deferral-WA	OTHER	-8,731	0	0	0	0	0	0	0	-8,731
2540000	REGULATORY LIAB	288286	Reg Liab-Excess Income Tax Deferral-WY	OTHER	-5,322	0	0	0	0	0	0	0	-5,322
2540000	REGULATORY LIAB	288295	RegL - BPA Balancing Accts - Recl to Cur	OTHER	3,252	0	0	0	0	0	0	0	3,252
2540000	REGULATORY LIAB	288405	Reg Liab-OR Direct Access 5 yr Opt Out	OTHER	-4,614	0	0	0	0	0	0	0	-4,614
2540000	REGULATORY LIAB	288411	Reg Liab - WA-Accel Depr 2015 GRC	WA	-33,340	0	0	-33,340	0	0	0	0	0
2540000	REGULATORY LIAB	288412	Reg Liab - Depr Decrease Deferral - OR	OTHER	-5,863	0	0	0	0	0	0	0	-5,863
2540000	REGULATORY LIAB	288413	Reg Liab - Depr Decrease Deferral - WA	WA	7	0	0	7	0	0	0	0	0
2540000	REGULATORY LIAB	288420	Reg Liab - CA GHG Allowance Revenues	OTHER	522	0	0	0	0	0	0	0	522
2540000	REGULATORY LIAB	288422	Reg Liab - CA Solar (SOMAH)-GHG Funds	OTHER	-3,298	0	0	0	0	0	0	0	-3,298
2540000	REGULATORY LIAB	288423	RegL - CA GHG Allowances - Recl to Curr	OTHER	4,462	0	0	0	0	0	0	0	4,462

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Miscellaneous Rate Base
Balances as of June 2019
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	288424	RegL - CA GHG Allowances - Balance Recl	OTHER	-1,686	0	0	0	0	0	0	0	-1,686
2540000	REGULATORY LIAB	288454	RegL - UT RECs in Rates - Balance Recl	OTHER	-303	0	0	0	0	0	0	0	-303
2540000	REGULATORY LIAB	288456	RegL - WY RECs in Rates - Balance Recl	OTHER	-86	0	0	0	0	0	0	0	-86
2540000	REGULATORY LIAB	288459	Reg Liab - Def RECs in Rates - Reclass	OTHER	-108	0	0	0	0	0	0	0	-108
2540000	REGULATORY LIAB	288463	RegL - OR Def Exc NPC - Recl to Curr	OTHER	3,515	0	0	0	0	0	0	0	3,515
2540000	REGULATORY LIAB	288465	RegL - WA Def Exc NPC - Recl to Curr	OTHER	7,832	0	0	0	0	0	0	0	7,832
2540000	REGULATORY LIAB	288470	Reg L-WA Decoupling Mechanism-Reclass	OTHER	-2,211	0	0	0	0	0	0	0	-2,211
2540000	REGULATORY LIAB	288481	RegL - CA Solar Feed-In - Recl to Curr	OTHER	623	0	0	0	0	0	0	0	623
2540000	REGULATORY LIAB	288484	RegL - UT Solar Feed-In - Recl to Curr	OTHER	19,203	0	0	0	0	0	0	0	19,203
2540000	REGULATORY LIAB	288491	RegL - CA Solar Feed-In - Balance Recl	OTHER	-623	0	0	0	0	0	0	0	-623
2540000	REGULATORY LIAB	288494	RegL - UT Solar Feed-In - Balance Recl	OTHER	-23,998	0	0	0	0	0	0	0	-23,998
2540000	REGULATORY LIAB	288749	RegL - Insurance Reserves - Reclass	OTHER	0	0	0	0	0	0	0	0	0
2540000	REGULATORY LIAB	288817	RegL - DSM - CA - Reclass to Current	OTHER	2,453	0	0	0	0	0	0	0	2,453
2540000	REGULATORY LIAB	288819	Reg Liab - DSM - CA - Balance Reclass	OTHER	-2,453	0	0	0	0	0	0	0	-2,453
2540000	REGULATORY LIAB	288827	RegL - DSM - ID - Reclass to Current	OTHER	880	0	0	0	0	0	0	0	880
2540000	REGULATORY LIAB	288829	Reg Liab - DSM - ID - Balance Reclass	OTHER	-880	0	0	0	0	0	0	0	-880
2540000	REGULATORY LIAB	288847	RegL - DSM - UT - Reclass to Current	OTHER	12,459	0	0	0	0	0	0	0	12,459
2540000	REGULATORY LIAB	288849	Reg Liab - DSM - UT - Balance Reclass	OTHER	-21,640	0	0	0	0	0	0	0	-21,640
2540000	REGULATORY LIAB	288857	RegL - DSM - WA - Reclass to Current	OTHER	3,933	0	0	0	0	0	0	0	3,933
2540000	REGULATORY LIAB	288859	Reg Liab - DSM - WA - Balance Reclass	OTHER	-3,933	0	0	0	0	0	0	0	-3,933
2540000	REGULATORY LIAB	288867	RegL - DSM - WY - Reclass to Current	OTHER	406	0	0	0	0	0	0	0	406
2540000	REGULATORY LIAB	288869	Reg Liab - DSM - WY - Balance Reclass	OTHER	-406	0	0	0	0	0	0	0	-406
2540000	REGULATORY LIAB	288941	Reg Liab - Protected PP&E ARAM - CA	CA	-1,299	-1,299	0	0	0	0	0	0	0
2540000	REGULATORY LIAB	288942	Reg Liab - Protected PP&E ARAM - ID	IDU	-3,100	0	0	0	0	0	-3,100	0	0
2540000	REGULATORY LIAB	288943	Reg Liab - Protected PP&E ARAM - OR	OR	-14,709	0	-14,709	0	0	0	0	0	0
2540000	REGULATORY LIAB	288944	Reg Liab - Protected PP&E ARAM - UT	UT	-26,440	0	0	0	0	-26,440	0	0	0
2540000	REGULATORY LIAB	288945	Reg Liab - Protected PP&E ARAM - WA	WA	-3,782	0	0	-3,782	0	0	0	0	0
2540000	REGULATORY LIAB	288946	Reg Liab - Protected PP&E ARAM - WY	WYU	-8,642	0	0	0	-8,642	0	0	0	0
2540000	REGULATORY LIAB	288995	RegL - Other - Recl to Curr	OTHER	9,227	0	0	0	0	0	0	0	9,227
2540000 Total					**-308,257**	**-2,408**	**-30,478**	**-39,198**	**-20,598**	**-26,440**	**-4,653**	**-18**	**-184,464**
2541050	FAS143 ARO REG LIAB	288506	ARO/REG DIFF - TROJAN NUCLEAR PLANT	TROJD	-2,639	-40	-682	-207	-392	-1,158	-159	-1	0
2541050	FAS143 ARO REG LIAB	288906	ARO/Reg Diff - Trojan - WA portion	WA	259	0	0	259	0	0	0	0	0
2541050 Total					**-2,380**	**-40**	**-682**	**52**	**-392**	**-1,158**	**-159**	**-1**	**0**
Grand Total					**-579,501**	**-7,874**	**-100,688**	**-61,018**	**-63,970**	**-142,644**	**-22,768**	**-93**	**-180,447**

Regulatory Assets
Balances as of June 2019
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	1,009	0	0	0	0	0	0	0	1,009
1242000	PAC PWR-INT FREE LN	0	INT FREE-PPL	WA	7	0	0	7	0	0	0	0	0
1242000 Total					**1,016**	**0**	**0**	**7**	**0**	**0**	**0**	**0**	**1,009**
1243200	OR-VAR WEATHER LOANS	0	INT BEARING VAR%-PPL	OR	0	0	0	0	0	0	0	0	0
1243200	OR-VAR WEATHER LOANS	0	INT BEARING VAR%-PPL	WA	0	0	0	0	0	0	0	0	0
1243200 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
1244100	ENERGY FINANSWER	0	ENERGY FINANSWER	SO	0	0	0	0	0	0	0	0	0
1244100	ENERGY FINANSWER	0	ENERGY FINANSWER	UT	8	0	0	0	0	8	0	0	0
1244100 Total					**8**	**0**	**0**	**0**	**0**	**8**	**0**	**0**	**0**
1244500	HOME COMFORT	0	HOME COMFORT	CA	6	6	0	0	0	0	0	0	0
1244500	HOME COMFORT	0	HOME COMFORT	OTHER	-1	0	0	0	0	0	0	0	-1
1244500	HOME COMFORT	0	HOME COMFORT	SO	-5	0	-1	0	-1	-2	0	0	0
1244500 Total					**0**	**6**	**-1**	**0**	**-1**	**-2**	**0**	**0**	**-1**
1244900	FINANSWER 12,000	0	"FINANSWER 12,000"	OTHER	-1	0	0	0	0	0	0	0	-1
1244900	FINANSWER 12,000	0	"FINANSWER 12,000"	UT	1	0	0	0	0	1	0	0	0
1244900 Total					**0**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**-1**
1245300	IRRIGATION FINANSW	0	IRRIGATION FINANSWER	CA	20	20	0	0	0	0	0	0	0
1245300	IRRIGATION FINANSW	0	IRRIGATION FINANSWER	OTHER	-20	0	0	0	0	0	0	0	-20
1245300 Total					**0**	**20**	**0**	**0**	**0**	**0**	**0**	**0**	**-20**
1245400	RETROFIT ENGY FINANS	0	RETRO ENERGY FINANS	OTHER	4	0	0	0	0	0	0	0	4
1245400	RETROFIT ENGY FINANS	0	RETRO ENERGY FINANS	UT	-4	0	0	0	0	-4	0	0	0
1245400 Total					**0**	**0**	**0**	**0**	**0**	**-4**	**0**	**0**	**4**
1249000	RESV UNCOLL ESC&WZ	0	ESC - RESERVE	OTHER	-230	0	0	0	0	0	0	0	-230
1249000	RESV UNCOLL ESC&WZ	0	ESC - RESERVE	WA	-4	0	0	-4	0	0	0	0	0
1249000 Total					**-234**	**0**	**0**	**-4**	**0**	**0**	**0**	**0**	**-230**
1823000	DSR REGULATORY ASSET	0	DSR REGULATORY ASSETS	IDU	-68	0	0	0	0	0	-68	0	0
1823000	DSR REGULATORY ASSET	0	DSR REGULATORY ASSETS	OTHER	-15,637	0	0	0	0	0	0	0	-15,637
1823000	DSR REGULATORY ASSET	0	DSR REGULATORY ASSETS	WYP	-904	0	0	0	-904	0	0	0	0
1823000 Total					**-16,610**	**0**	**0**	**0**	**-904**	**0**	**-68**	**0**	**-15,637**
1823700	OTH REGA-ENERGY WEST	186801	Reg Asset-Deer Creek-Elec Plt In Svc	SE	69,504	1,011	17,446	5,225	11,107	30,134	4,558	23	0
1823700	OTH REGA-ENERGY WEST	186802	Reg Asset-Deer Creek-EPIS Intangibles	SE	1,078	16	271	81	172	467	71	0	0
1823700	OTH REGA-ENERGY WEST	186805	Reg Asset-Deer Creek-CWIP	SE	3,960	58	994	298	633	1,717	260	1	0
1823700	OTH REGA-ENERGY WEST	186806	Reg Asset-Deer Creek-PS&I	SE	1,614	23	405	121	258	700	106	1	0
1823700	OTH REGA-ENERGY WEST	186811	Reg Asset-Deer Creek Sale-EPIS	SE	9,902	144	2,486	744	1,582	4,293	649	3	0
1823700	OTH REGA-ENERGY WEST	186812	Contra RA-DCM PP&E-OR-To G/L Bal Acct	OR	399	0	399	0	0	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186815	Reg Asset-Deer Creek Sale-CWIP	SE	94	1	23	7	15	41	6	0	0
1823700	OTH REGA-ENERGY WEST	186816	Contra RA-DCM PP&E-To Joint Owners	SE	-4,699	-68	-1,180	-353	-751	-2,037	-308	-2	0
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	CA	1,223	1,223	0	0	0	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	OR	-3,866	0	-3,866	0	0	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	SE	-79,015	-1,149	-19,834	-5,940	-12,627	-34,258	-5,182	-26	0
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	UT	281	0	0	0	0	281	0	0	0

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Regulatory Assets
Balances as of June 2019
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	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	WA	5,486	0	0	5,486	0	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	WYU	3,712	0	0	0	3,712	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186820	Reg Asset-Deer Creek Mine ARO	SE	6,064	88	1,522	456	969	2,629	398	2	0
1823700	OTH REGA-ENERGY WEST	186825	Reg Asset-Deer Creek Mine M&S	SE	4,492	65	1,128	338	718	1,948	295	1	0
1823700	OTH REGA-ENERGY WEST	186826	Reg Asset-Deer Creek-Prepaid Royalties	SE	843	12	212	63	135	365	55	0	0
1823700	OTH REGA-ENERGY WEST	186828	Reg Asset-Deer Creek-Recovery Royalties	SE	7,538	110	1,892	567	1,205	3,268	494	2	0
1823700	OTH REGA-ENERGY WEST	186829	Contra RA-DCM Closure-Royalties Amortz	WYU	-487	0	0	0	-487	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186830	Reg Asset-Deer Creek-Union Suppl Ben	SE	1,612	23	405	121	258	699	106	1	0
1823700	OTH REGA-ENERGY WEST	186833	Reg Asset-Deer Creek-Nonunion Severance	SE	2,500	36	628	188	399	1,084	164	1	0
1823700	OTH REGA-ENERGY WEST	186835	Reg Asset-Deer Creek-Misc Closure Costs	SE	44,848	652	11,258	3,372	7,167	19,444	2,941	15	0
1823700	OTH REGA-ENERGY WEST	186836	Contra RA-DCM Closure-To Joint Owners	SE	-2,803	-41	-704	-211	-448	-1,215	-184	-1	0
1823700	OTH REGA-ENERGY WEST	186837	Contra RA-DCM Closure-Amortz & Oth Adjs	UT	5,043	0	0	0	0	5,043	0	0	0
1823700	OTH REGA-ENERGY WEST	186837	Contra RA-DCM Closure-Amortz & Oth Adjs	WYU	-10,511	0	0	0	-10,511	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186839	Reg Asset-Deer Creek-Tax Flow-Through	SE	2,979	43	748	224	476	1,291	195	1	0
1823700	OTH REGA-ENERGY WEST	186841	Contra Reg Asset-Deer Creek Aband-CA	CA	-1,332	-1,332	0	0	0	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186844	Contra Reg Asset-Deer Creek Aband-UT	UT	-924	0	0	0	0	-924	0	0	0
1823700	OTH REGA-ENERGY WEST	186845	Contra Reg Asset-Deer Creek Aband-WA	WA	-5,975	0	0	-5,975	0	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186846	Contra Reg Asset-Deer Creek Aband-WY	WYU	-376	0	0	0	-376	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186851	Contra Reg Asset-Deer Creek Closure-CA	CA	-1,113	-1,113	0	0	0	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186852	CONTRA REG ASSET-DEER CREEK CLOSURE-ID	IDU	-1,718	0	0	0	0	0	-1,718	0	0
1823700	OTH REGA-ENERGY WEST	186853	Contra Reg Asset-Deer Creek Closure-OR	OR	-8,284	0	-8,284	0	0	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186854	CONTRA REG ASSET-DEER CREEK CLOSURE-UT	UT	-1,483	0	0	0	0	-1,483	0	0	0
1823700	OTH REGA-ENERGY WEST	186855	Contra Reg Asset-Deer Creek Closure-WA	WA	-4,994	0	0	-4,994	0	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186860	RA-Deer Creek-ROR Offset-Assets Sold	UT	-1,734	0	0	0	0	-1,734	0	0	0
1823700	OTH REGA-ENERGY WEST	186860	RA-Deer Creek-ROR Offset-Assets Sold	WYU	-107	0	0	0	-107	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186861	RA-Deer Creek-ROR Offset-Fuel Inventory	IDU	-979	0	0	0	0	0	-979	0	0
1823700	OTH REGA-ENERGY WEST	186861	RA-Deer Creek-ROR Offset-Fuel Inventory	UT	-6,220	0	0	0	0	-6,220	0	0	0
1823700	OTH REGA-ENERGY WEST	186861	RA-Deer Creek-ROR Offset-Fuel Inventory	WYU	-419	0	0	0	-419	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186862	RA-Deer Creek-ROR Offset-Fossil Rock	UT	-5,551	0	0	0	0	-5,551	0	0	0
1823700	OTH REGA-ENERGY WEST	186862	RA-Deer Creek-ROR Offset-Fossil Rock	WYU	-343	0	0	0	-343	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186863	RA-Deer Creek-ROR Offset-Note Intrst-ID	IDU	-180	0	0	0	0	0	-180	0	0
1823700	OTH REGA-ENERGY WEST	186870	RA-DC ROR Offset-Assets Sold-Amortz	WYP	107	0	0	0	107	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186871	RA-DC ROR Offset-Fuel Inventory-Amortz	WYP	365	0	0	0	365	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186872	RA-DC ROR Offset-Fossil Rock-Amortz	WYP	300	0	0	0	300	0	0	0	0
1823700	OTH REGA-ENERGY WEST	186881	Reg Asset-UMWA Pension Trust Oblig	SE	115,119	1,674	28,897	8,654	18,396	49,911	7,549	37	0
1823700	OTH REGA-ENERGY WEST	186886	Contra RA-UMWA Pens W/D-To Joint Owners	OTHER	-4,753	0	0	0	0	0	0	0	-4,753
1823700	OTH REGA-ENERGY WEST	186891	Contra Reg Asset-UMWA Pension Trust-CA	OTHER	-1,805	0	0	0	0	0	0	0	-1,805
1823700	OTH REGA-ENERGY WEST	186895	Contra Reg Asset-UMWA Pension Trust-WA	OTHER	-8,097	0	0	0	0	0	0	0	-8,097
1823700 Total					**131,293**	**1,477**	**34,844**	**8,472**	**21,905**	**69,893**	**9,296**	**60**	**-14,654**
1823870	DEFERRED PENSION	187017	FAS 158 Pen Liab Adj	SO	459,735	10,260	125,118	35,392	62,509	199,978	26,384	94	0
1823870	DEFERRED PENSION	187018	CONTRA FAS 158 PENSION REG ASSET	SO	-22,067	-492	-6,006	-1,699	-3,000	-9,599	-1,266	-4	0

Regulatory Assets
Balances as of June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823870	DEFERRED PENSION	187607	Contra Reg Asset 2016 Pension Plan CTG	SO	-820	-18	-223	-63	-112	-357	-47	0	0
1823870	DEFERRED PENSION	187621	Reg Asset FAS - 158	SO	-2,038	-45	-555	-157	-277	-886	-117	0	0
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	CA	-127	-127	0	0	0	0	0	0	0
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	SO	8,323	186	2,265	641	1,132	3,620	478	2	0
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	WA	-660	0	0	-660	0	0	0	0	0
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	WYU	-1,236	0	0	0	-1,236	0	0	0	0
1823870	DEFERRED PENSION	187640	Reg Asset-PostRet Sttlmt Loss-CC-UT	UT	1,398	0	0	0	0	1,398	0	0	0
1823870	DEFERRED PENSION	187641	Reg Asset-PostRet Sttlmt Loss-CC-WY	WYU	11	0	0	0	11	0	0	0	0
1823870 Total					**442,519**	**9,762**	**120,600**	**33,454**	**59,027**	**194,155**	**25,431**	**90**	**0**
1823910	ENVIR CST UNDR AMORT	102465	UTAH METALS CLEANUP	SO	321	7	87	25	44	140	18	0	0
1823910	ENVIR CST UNDR AMORT	102570	D-SM RETAIL MINOR SITES	SO	3	0	1	0	0	2	0	0	0
1823910	ENVIR CST UNDR AMORT	103408	D-SM RETAIL MINOR SITES	SO	3,525	79	959	271	479	1,533	202	1	0
1823910	ENVIR CST UNDR AMORT	103412	D-SM RETAIL MINOR SITES	SO	47	1	13	4	6	20	3	0	0
1823910	ENVIR CST UNDR AMORT	103413	D-SM RETAIL MINOR SITES	SO	177	4	48	14	24	77	10	0	0
1823910	ENVIR CST UNDR AMORT	103418	ASTORIA YOUNGS BAY CLEANUP	SO	10	0	3	1	1	5	1	0	0
1823910	ENVIR CST UNDR AMORT	103419	ASTORIA YOUNGS BAY CLEANUP	SO	132	3	36	10	18	57	8	0	0
1823910	ENVIR CST UNDR AMORT	103420	ASTORIA YOUNGS BAY CLEANUP	SO	269	6	73	21	37	117	15	0	0
1823910	ENVIR CST UNDR AMORT	103424	SILVER BELL MINE ENVIRONMENTAL REMED	SO	8	0	2	1	1	3	0	0	0
1823910	ENVIR CST UNDR AMORT	103425	SILVER BELL MINE ENVIRONMENTAL REMED	SO	28	1	8	2	4	12	2	0	0
1823910	ENVIR CST UNDR AMORT	103426	SILVER BELL MINE ENVIRONMENTAL REMED	SO	5,531	123	1,505	426	752	2,406	317	1	0
1823910	ENVIR CST UNDR AMORT	103438	WASHINGTON NON-DEFERRED COSTS	WA	-8	0	0	-8	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103439	WASHINGTON NON-DEFERRED COSTS	WA	-34	0	0	-34	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103440	WASHINGTON NON-DEFERRED COSTS	WA	-83	0	0	-83	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103445	American Barrel (UT)	SO	377	8	103	29	51	164	22	0	0
1823910	ENVIR CST UNDR AMORT	103446	Astoria/Unocal (Downtown)	SO	767	17	209	59	104	334	44	0	0
1823910	ENVIR CST UNDR AMORT	103447	Big Fork Hydro Plant (MT)	SO	348	8	95	27	47	152	20	0	0
1823910	ENVIR CST UNDR AMORT	103448	Bridger Coal Fuel Oil Spill	SO	458	10	125	35	62	199	26	0	0
1823910	ENVIR CST UNDR AMORT	103449	Bridger FGD Pond 1 Closure	SO	620	14	169	48	84	270	36	0	0
1823910	ENVIR CST UNDR AMORT	103450	Bridger Plant Oil Spills	SO	376	8	102	29	51	164	22	0	0
1823910	ENVIR CST UNDR AMORT	103451	Cedar Stream Plant (UT)	SO	28	1	8	2	4	12	2	0	0
1823910	ENVIR CST UNDR AMORT	103452	Dave Johnston Oil Spill	SO	890	20	242	69	121	387	51	0	0
1823910	ENVIR CST UNDR AMORT	103453	Eugene MGP (50% PCRP)	SO	97	2	26	7	13	42	6	0	0
1823910	ENVIR CST UNDR AMORT	103454	Everett MGP (2/3 PCRP)	SO	10	0	3	1	1	4	1	0	0
1823910	ENVIR CST UNDR AMORT	103455	Hunter Fuel Oil Spills	SO	98	2	27	8	13	42	6	0	0
1823910	ENVIR CST UNDR AMORT	103456	Huntington Ash Landfill	SO	303	7	83	23	41	132	17	0	0
1823910	ENVIR CST UNDR AMORT	103457	Idaho Falls Pole Yard	SO	1,163	26	316	90	158	506	67	0	0
1823910	ENVIR CST UNDR AMORT	103458	Jordan Plant Substation	SO	88	2	24	7	12	38	5	0	0
1823910	ENVIR CST UNDR AMORT	103459	Little Mountain Gas Plant	SO	594	13	162	46	81	259	34	0	0
1823910	ENVIR CST UNDR AMORT	103460	Montague Ranch (CA)	SO	76	2	21	6	10	33	4	0	0
1823910	ENVIR CST UNDR AMORT	103461	Naughton FGD Pond Closure	SO	167	4	45	13	23	73	10	0	0
1823910	ENVIR CST UNDR AMORT	103462	Ogden MGP	SO	2,862	64	779	220	389	1,245	164	1	0

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1823910	ENVIR CST UNDR AMORT	103464	Powerdale Hydro Plant	SO	0	0	0	0	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103465	Tacoma A St. (25% PCRP)	SO	30	1	8	2	4	13	2	0	0
1823910	ENVIR CST UNDR AMORT	103466	Portland Harbor Service Ctr	SO	2,771	62	754	213	377	1,205	159	1	0
1823910	ENVIR CST UNDR AMORT	103467	Wyodak Fuel Oil Spill	SO	73	2	20	6	10	32	4	0	0
1823910	ENVIR CST UNDR AMORT	103585	CLINE FALLS-HYDRO	SO	67	1	18	5	9	29	4	0	0
1823910	ENVIR CST UNDR AMORT	103737	Geneva Rock Bldg - Hunter Plant	SO	21	0	6	2	3	9	1	0	0
1823910	ENVIR CST UNDR AMORT	103851	Alturas Service Center (CA)	SO	5	0	1	0	1	2	0	0	0
1823910	ENVIR CST UNDR AMORT	103852	Pendleton Service Center (OR)	SO	3	0	1	0	0	1	0	0	0
1823910	ENVIR CST UNDR AMORT	103853	Sunnyside Service Center (WA)	SO	0	0	0	0	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103940	D-SM Retail Minor Sites - RMP - 2012	SO	186	4	51	14	25	81	11	0	0
1823910	ENVIR CST UNDR AMORT	103941	D-SM Retail Minor Sites - RMP - 2013	SO	291	7	79	22	40	127	17	0	0
1823910	ENVIR CST UNDR AMORT	103942	D-SM Retail Minor Sites - RMP - 2014	SO	563	13	153	43	77	245	32	0	0
1823910	ENVIR CST UNDR AMORT	103946	D-SM Retail Minor Sites - RMP - 2010	SO	47	1	13	4	6	21	3	0	0
1823910	ENVIR CST UNDR AMORT	103947	D-SM Retail Minor Sites - RMP - 2011	SO	106	2	29	8	14	46	6	0	0
1823910	ENVIR CST UNDR AMORT	103948	WASHINGTON NON-DEFERRED COSTS-SPPC PACIF	WA	-122	0	0	-122	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103949	WASHINGTON NON-DEFERRED COSTS-SPPC ROCKY	WA	-99	0	0	-99	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103950	WASHINGTON NON-DEFERRED COSTS-REMEDIATIO	WA	-127	0	0	-127	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103951	WASHINGTON NON-DEFERRED COSTS-REMEDIATIO	WA	-493	0	0	-493	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103952	WASHINGTON NON-DEFERRED COSTS-REMEDIATIO	WA	-133	0	0	-133	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103953	Wash Non-Def Costs - SPPC - RMP - 2012	WA	-66	0	0	-66	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103954	Wash Non-Def Costs - SPPC - RMP - 2013	WA	-115	0	0	-115	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103955	Wash Non-Def Costs - SPPC - RMP - 2014	WA	-251	0	0	-251	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103961	D-SM RETAIL MINOR SITES - RMP	SO	2,180	49	593	168	296	948	125	0	0
1823910	ENVIR CST UNDR AMORT	104072	FREEPORT SUBSTATION	SO	74	2	20	6	10	32	4	0	0
1823910	ENVIR CST UNDR AMORT	104108	Bors Property (OR) - 2016	SO	17	0	5	1	2	7	1	0	0
1823910	ENVIR CST UNDR AMORT	104112	Carbon Ash Spill (UT) - 2016	SO	2,949	66	803	227	401	1,283	169	1	0
1823910	ENVIR CST UNDR AMORT	104144	Naughton Oil Spill	SO	19	0	5	1	3	8	1	0	0
1823910	ENVIR CST UNDR AMORT	104175	Ririe Substation	SO	10	0	3	1	1	5	1	0	0
1823910	ENVIR CST UNDR AMORT	104197	Bridger Plant - FGD Pond 1	SO	37	1	10	3	5	16	2	0	0
1823910	ENVIR CST UNDR AMORT	104198	Bridger Plant - FGD Pond 2	SO	11	0	3	1	1	5	1	0	0
1823910	ENVIR CST UNDR AMORT	104199	Naughton Plant - FGD Pond 1	SO	80	2	22	6	11	35	5	0	0
1823910	ENVIR CST UNDR AMORT	104200	Naughton Plant - FGD Pond 2	SO	96	2	26	7	13	42	6	0	0
1823910	ENVIR CST UNDR AMORT	104201	Huntington Plant Ash Landfill	SO	53	1	14	4	7	23	3	0	0
1823910	ENVIR CST UNDR AMORT	104202	Dave Johnston Pond 4A & 4B	SO	63	1	17	5	9	28	4	0	0
1823910	ENVIR CST UNDR AMORT	104203	Colstrip Pond	SO	42	1	11	3	6	18	2	0	0
1823910	ENVIR CST UNDR AMORT	104204	Cholla Ash-Flyash Pond	SO	1	0	0	0	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104206	Naughton South Ash Pond	SO	45	1	12	3	6	20	3	0	0
1823910	ENVIR CST UNDR AMORT	104210	American Barrel (UT)-WA	WA	-10	0	0	-10	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104211	Astoria/Unocal (Downtown)-WA	WA	-19	0	0	-19	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104212	ASTORIA YOUNGS BAY CLEANUP-WA	WA	-1	0	0	-1	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104213	Big Fork Hydro Plant (MT)-WA	WA	-9	0	0	-9	0	0	0	0	0

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1823910	ENVIR CST UNDR AMORT	104214	Bors Property (OR) - WA	WA	-1	0	0	-1	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104215	Bridger Coal Fuel Oil Spill - WA	WA	-16	0	0	-16	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104216	Bridger FGD Pond 1 Closure-WA	WA	-11	0	0	-11	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104218	Bridger Plant - FGD Pond 1-WA	WA	-7	0	0	-7	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104219	Bridger Plant - FGD Pond 2-WA	WA	-1	0	0	-1	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104220	Bridger Plant Oil Spills-2018	WA	-8	0	0	-8	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104221	Carbon Ash Spill (UT) - WA	WA	-20	0	0	-20	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104222	Cedar Steam - WA	WA	0	0	0	0	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104223	Colstrip Pond - WA	WA	-3	0	0	-3	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104224	Cholla Ash - WA	WA	0	0	0	0	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104225	DJ Oil Spill - WA	WA	-5	0	0	-5	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104226	DJ 4A&4B - WA	WA	-4	0	0	-4	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104227	Eugene MGP (50%PCRP) - WA	WA	-1	0	0	-1	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104228	Everett MGP (2/3 PCRP) - WA	WA	0	0	0	0	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104229	Hunter Plant - WA	WA	-11	0	0	-11	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104230	Huntington Ash- WA	WA	-9	0	0	-9	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104231	Idaho Falls Pole Yard- WA	WA	-26	0	0	-26	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104232	Jordan Plant Substation- WA	WA	0	0	0	0	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104233	Montague Ranch - WA	WA	0	0	0	0	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104234	Naughton Plant FGDP 1 - WA	WA	-6	0	0	-6	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104235	Naughton Plant FGDP 2 - WA	WA	-7	0	0	-7	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104236	Naughton Plant FGDP Closure - WA	WA	-3	0	0	-3	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104239	Naughton South Ash Pond - WA	WA	-3	0	0	-3	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104240	Ogden MGP - WA	WA	-46	0	0	-46	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104241	Olympia - WA	WA	0	0	0	0	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104242	Portland Harbor Srce Cntrl - WA	WA	-70	0	0	-70	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104244	Silver Bell/Telluride - WA	WA	-89	0	0	-89	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104245	Tacoma A St. (25% PCRP) - WA	WA	-1	0	0	-1	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104246	Utah Metal East - WA	WA	0	0	0	0	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104247	Wyodak Oil Spill - WA	WA	-2	0	0	-2	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104268	Rocky Mountain - WA	WA	-46	0	0	-46	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104269	Pac Power - WA	WA	-85	0	0	-85	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	104296	NTO Parking Lot-Asbestos 2018	SO	206	5	56	16	28	90	12	0	0
1823910	ENVIR CST UNDR AMORT	104297	NTO Parking Lot Asbestos - WA 2018	WA	-14	0	0	-14	0	0	0	0	0
1823910 Total					**27,357**	**657**	**8,008**	**199**	**4,001**	**12,799**	**1,689**	**6**	**0**
1823920	DSR COSTS AMORTIZED	0	DSR COST AMORT	IDU	68	0	0	0	0	0	68	0	0
1823920	DSR COSTS AMORTIZED	0	DSR COST AMORT	OTHER	135,415	0	0	0	0	0	0	0	135,415
1823920	DSR COSTS AMORTIZED	102030	ENERGY FINANSWER - WASHINGTON	OTHER	5,065	0	0	0	0	0	0	0	5,065
1823920	DSR COSTS AMORTIZED	102032	INDUSTRIAL FINANSWER - WASHINGTON	OTHER	26,337	0	0	0	0	0	0	0	26,337
1823920	DSR COSTS AMORTIZED	102033	LOW INCOME - WASHINGTON	OTHER	10,718	0	0	0	0	0	0	0	10,718
1823920	DSR COSTS AMORTIZED	102034	SELF AUDIT - WASHINGTON	OTHER	14	0	0	0	0	0	0	0	14

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1823920	DSR COSTS AMORTIZED	102036	COMMERCIAL SMALL RETROFIT - WASHINGTON	OTHER	788	0	0	0	0	0	0	0	788
1823920	DSR COSTS AMORTIZED	102037	INDUSTRIAL SMALL RETROFIT - WASHINGTON	OTHER	13	0	0	0	0	0	0	0	13
1823920	DSR COSTS AMORTIZED	102038	COMMERCIAL RETROFIT LIGHTING - WASHINGTO	OTHER	624	0	0	0	0	0	0	0	624
1823920	DSR COSTS AMORTIZED	102039	INDUSTRIAL RETROFIT LIGHTING-WA	OTHER	88	0	0	0	0	0	0	0	88
1823920	DSR COSTS AMORTIZED	102040	NEEA - WASHINGTON	OTHER	11,185	0	0	0	0	0	0	0	11,185
1823920	DSR COSTS AMORTIZED	102043	ENERGY CODE DEVELOPMENT	OTHER	2	0	0	0	0	0	0	0	2
1823920	DSR COSTS AMORTIZED	102044	HOME COMFORT - WASHINGTON	OTHER	162	0	0	0	0	0	0	0	162
1823920	DSR COSTS AMORTIZED	102045	WEATHERIZATION - WASHINGTON	OTHER	22	0	0	0	0	0	0	0	22
1823920	DSR COSTS AMORTIZED	102046	HASSLE FREE	OTHER	41	0	0	0	0	0	0	0	41
1823920	DSR COSTS AMORTIZED	102072	COMPACT FLUORESCENT LAMPS - WASHINGTON	OTHER	1,183	0	0	0	0	0	0	0	1,183
1823920	DSR COSTS AMORTIZED	102127	RESIDENTIAL PROGRAM RESEARCH - WA	OTHER	24	0	0	0	0	0	0	0	24
1823920	DSR COSTS AMORTIZED	102128	WA REVENUE RECOVERY - SBC OFFSET	OTHER	-114,872	0	0	0	0	0	0	0	-114,872
1823920	DSR COSTS AMORTIZED	102131	ENERGY FINANSWER - UTAH 2001/2002	OTHER	1,280	0	0	0	0	0	0	0	1,280
1823920	DSR COSTS AMORTIZED	102133	INDUSTRIAL FINANSWER - UTAH 2001/2002	OTHER	1,353	0	0	0	0	0	0	0	1,353
1823920	DSR COSTS AMORTIZED	102138	COMPACT FLUOR LAMPS (CFL) UT 2001/2002	OTHER	4,202	0	0	0	0	0	0	0	4,202
1823920	DSR COSTS AMORTIZED	102147	COMMERCIAL SMALL RETROFIT - UT 2001/2002	OTHER	848	0	0	0	0	0	0	0	848
1823920	DSR COSTS AMORTIZED	102148	INDUSTRIAL SMALL RETROFIT - UT 2002	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	102149	COMMERCIAL RETROFIT LIGHTING - UT 2001/2	OTHER	498	0	0	0	0	0	0	0	498
1823920	DSR COSTS AMORTIZED	102150	INDUSTRIAL RETROFIT LIGHTING - UT 2001/2	OTHER	82	0	0	0	0	0	0	0	82
1823920	DSR COSTS AMORTIZED	102185	WEB AUDIT PILOT - WA	OTHER	527	0	0	0	0	0	0	0	527
1823920	DSR COSTS AMORTIZED	102186	APPLIANCE REBATE - WA	OTHER	18	0	0	0	0	0	0	0	18
1823920	DSR COSTS AMORTIZED	102195	INDUSTRIAL RETROFIT LIGHTING - UT 2002	OTHER	71	0	0	0	0	0	0	0	71
1823920	DSR COSTS AMORTIZED	102196	POWER FORWARD UT 2002	OTHER	115	0	0	0	0	0	0	0	115
1823920	DSR COSTS AMORTIZED	102205	A/C LOAD CONTROL PGM - RESIDENTIAL - UT	OTHER	28	0	0	0	0	0	0	0	28
1823920	DSR COSTS AMORTIZED	102206	SCHOOL ENERGY EDUCATION - WA	OTHER	3,807	0	0	0	0	0	0	0	3,807
1823920	DSR COSTS AMORTIZED	102209	AIR CONDITIONING - UT 2002	OTHER	24	0	0	0	0	0	0	0	24
1823920	DSR COSTS AMORTIZED	102213	REFRIGERATOR RECYCLING PGM - UT 2003	OTHER	1,509	0	0	0	0	0	0	0	1,509
1823920	DSR COSTS AMORTIZED	102214	REFRIGERATOR RECYCLING PGM - WA	OTHER	3,675	0	0	0	0	0	0	0	3,675
1823920	DSR COSTS AMORTIZED	102223	A/C LOAD CONTROL - RESIDENTIAL UT 2003	OTHER	460	0	0	0	0	0	0	0	460
1823920	DSR COSTS AMORTIZED	102225	AIR CONDITIONING - UT 2003	OTHER	2,564	0	0	0	0	0	0	0	2,564
1823920	DSR COSTS AMORTIZED	102226	COMMERCIAL RETROFIT LIGHTING - UT 2003	OTHER	1,187	0	0	0	0	0	0	0	1,187
1823920	DSR COSTS AMORTIZED	102227	COMMERCIAL SMALL RETROFIT - UT 2003	OTHER	895	0	0	0	0	0	0	0	895
1823920	DSR COSTS AMORTIZED	102228	COMPACT FLOURESCENT LAMP (CFL) - UT 2002	OTHER	13	0	0	0	0	0	0	0	13
1823920	DSR COSTS AMORTIZED	102229	ENERGY FINANSWER - UT 2003	OTHER	1,542	0	0	0	0	0	0	0	1,542
1823920	DSR COSTS AMORTIZED	102230	INDUSTRIAL FINANSWER - UT 2003	OTHER	1,658	0	0	0	0	0	0	0	1,658
1823920	DSR COSTS AMORTIZED	102231	INDUSTRIAL RETROFIT LIGHTING - UT 2003	OTHER	191	0	0	0	0	0	0	0	191
1823920	DSR COSTS AMORTIZED	102232	INDUSTRIAL SMALL RETROFIT - UTAH - 2003	OTHER	14	0	0	0	0	0	0	0	14
1823920	DSR COSTS AMORTIZED	102233	POWER FORWARD - UT 2003	OTHER	-27	0	0	0	0	0	0	0	-27
1823920	DSR COSTS AMORTIZED	102245	CA REVENUE RECOVERY - BALANCING ACCT	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	102327	COMMERCIAL SELF-DIRECT UT 2003	OTHER	4	0	0	0	0	0	0	0	4
1823920	DSR COSTS AMORTIZED	102328	INDUSTRIAL SELF-DIRECT UT 2003	OTHER	7	0	0	0	0	0	0	0	7

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1823920	DSR COSTS AMORTIZED	102336	LOW INCOME - UTAH - 2004	OTHER	22	0	0	0	0	0	0	0	22
1823920	DSR COSTS AMORTIZED	102337	REFRIGERATOR RECYCLING PGM - UT 2004	OTHER	3,581	0	0	0	0	0	0	0	3,581
1823920	DSR COSTS AMORTIZED	102338	AC LOAD CONTROL - RESIDENTIAL UT 2004	OTHER	2,910	0	0	0	0	0	0	0	2,910
1823920	DSR COSTS AMORTIZED	102339	AIR CONDITIONING - UT 2004	OTHER	3,026	0	0	0	0	0	0	0	3,026
1823920	DSR COSTS AMORTIZED	102340	COMMERCIAL RETROFIT LIGHTING - UT 2004	OTHER	1,547	0	0	0	0	0	0	0	1,547
1823920	DSR COSTS AMORTIZED	102341	COMMERCIAL SMALL RETROFIT - UT 2004	OTHER	285	0	0	0	0	0	0	0	285
1823920	DSR COSTS AMORTIZED	102342	COMPACT FLOURESCENT LAMPS (CFL) UT 2004	OTHER	-1	0	0	0	0	0	0	0	-1
1823920	DSR COSTS AMORTIZED	102343	ENERGY FINANSWER - UT 2004	OTHER	1,227	0	0	0	0	0	0	0	1,227
1823920	DSR COSTS AMORTIZED	102344	INDUSTRIAL FINANSWER - UT 2004	OTHER	2,562	0	0	0	0	0	0	0	2,562
1823920	DSR COSTS AMORTIZED	102345	INDUSTRIAL RETROFIT - UT 2004	OTHER	230	0	0	0	0	0	0	0	230
1823920	DSR COSTS AMORTIZED	102346	INDUSTRIAL SMALL RETROFIT - UT 2004	OTHER	51	0	0	0	0	0	0	0	51
1823920	DSR COSTS AMORTIZED	102347	POWER FORWARD - UT 2004	OTHER	54	0	0	0	0	0	0	0	54
1823920	DSR COSTS AMORTIZED	102348	COMMERCIAL SELF-DIRECT - UT 2004	OTHER	89	0	0	0	0	0	0	0	89
1823920	DSR COSTS AMORTIZED	102349	INDUSTRIAL SELF-DIRECT - UT 2004	OTHER	129	0	0	0	0	0	0	0	129
1823920	DSR COSTS AMORTIZED	102443	ESIDENTIAL NEW CONSTRUCTION - WASHINGTON	OTHER	561	0	0	0	0	0	0	0	561
1823920	DSR COSTS AMORTIZED	102444	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	76	0	0	0	0	0	0	0	76
1823920	DSR COSTS AMORTIZED	102458	COMMERCIAL FINANSWER EXPRESS - WASHINGTO	OTHER	9,257	0	0	0	0	0	0	0	9,257
1823920	DSR COSTS AMORTIZED	102459	INDUSTRIAL FINANSWER EXPRESS - WASHINGTO	OTHER	3,275	0	0	0	0	0	0	0	3,275
1823920	DSR COSTS AMORTIZED	102460	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	446	0	0	0	0	0	0	0	446
1823920	DSR COSTS AMORTIZED	102461	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	146	0	0	0	0	0	0	0	146
1823920	DSR COSTS AMORTIZED	102462	UTAH REVENUE RECOVERY - SBC OFFSET	OTHER	-587,832	0	0	0	0	0	0	0	-587,832
1823920	DSR COSTS AMORTIZED	102502	RETROFIT COMMISSIONING PROGRAM - UTAH	OTHER	2	0	0	0	0	0	0	0	2
1823920	DSR COSTS AMORTIZED	102503	C&I LIGHTING LOAD CONTROL - UTAH - 2004	OTHER	23	0	0	0	0	0	0	0	23
1823920	DSR COSTS AMORTIZED	102532	LOW INCOME - UTAH - 2005	OTHER	48	0	0	0	0	0	0	0	48
1823920	DSR COSTS AMORTIZED	102533	REFRIGERATOR RECYCLING PGM- UTAH - 2005	OTHER	3,306	0	0	0	0	0	0	0	3,306
1823920	DSR COSTS AMORTIZED	102534	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	3,060	0	0	0	0	0	0	0	3,060
1823920	DSR COSTS AMORTIZED	102535	AIR CONDITIONING - UTAH - 2005	OTHER	2,347	0	0	0	0	0	0	0	2,347
1823920	DSR COSTS AMORTIZED	102536	COMMERCIAL RETROFIT LIGHTING - UTAH - 20	OTHER	65	0	0	0	0	0	0	0	65
1823920	DSR COSTS AMORTIZED	102537	COMMERCIAL SMALL RETROFIT - UTAH - 2005	OTHER	223	0	0	0	0	0	0	0	223
1823920	DSR COSTS AMORTIZED	102539	ENERGY FINANSWER - UTAH - 2005	OTHER	1,476	0	0	0	0	0	0	0	1,476
1823920	DSR COSTS AMORTIZED	102540	INDUSTRIAL FINANSWER - UTAH - 2005	OTHER	3,485	0	0	0	0	0	0	0	3,485
1823920	DSR COSTS AMORTIZED	102541	INDUSTRIAL RETROFIT LIGHTING - UTAH - 20	OTHER	60	0	0	0	0	0	0	0	60
1823920	DSR COSTS AMORTIZED	102543	POWER FORWARD - UTAH - 2005	OTHER	50	0	0	0	0	0	0	0	50
1823920	DSR COSTS AMORTIZED	102544	COMMERCIAL SELF-DIRECT - UTAH - 2005	OTHER	67	0	0	0	0	0	0	0	67
1823920	DSR COSTS AMORTIZED	102545	INDUSTRIAL SELF-DIRECT - UTAH - 2005	OTHER	103	0	0	0	0	0	0	0	103
1823920	DSR COSTS AMORTIZED	102546	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	944	0	0	0	0	0	0	0	944
1823920	DSR COSTS AMORTIZED	102547	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,967	0	0	0	0	0	0	0	1,967
1823920	DSR COSTS AMORTIZED	102548	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	421	0	0	0	0	0	0	0	421
1823920	DSR COSTS AMORTIZED	102549	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	105	0	0	0	0	0	0	0	105
1823920	DSR COSTS AMORTIZED	102550	C&I LIGHTING LOAD CONTROL - UTAH - 2005	OTHER	36	0	0	0	0	0	0	0	36
1823920	DSR COSTS AMORTIZED	102556	1823920/102556	OTHER	0	0	0	0	0	0	0	0	0

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1823920	DSR COSTS AMORTIZED	102562	APPLIANCE INCENTIVE - WASHWISE - WASHING	OTHER	53	0	0	0	0	0	0	0	53
1823920	DSR COSTS AMORTIZED	102586	IRRIGATION LOAD CONTROL - UTAH - 2005	OTHER	3	0	0	0	0	0	0	0	3
1823920	DSR COSTS AMORTIZED	102706	LOW INCOME-UTAH-2006	OTHER	119	0	0	0	0	0	0	0	119
1823920	DSR COSTS AMORTIZED	102707	REFRIGERATOR RECYCLING PGM-UTAH-2006	OTHER	3,752	0	0	0	0	0	0	0	3,752
1823920	DSR COSTS AMORTIZED	102708	A/C LOAD CONTROL-RESIDENTIAL/UTAH-2006	OTHER	8,624	0	0	0	0	0	0	0	8,624
1823920	DSR COSTS AMORTIZED	102709	AIR CONDITIONING-UTAH-2006	OTHER	1,499	0	0	0	0	0	0	0	1,499
1823920	DSR COSTS AMORTIZED	102712	ENERGY FINANSWER-UTAH-2006	OTHER	2,187	0	0	0	0	0	0	0	2,187
1823920	DSR COSTS AMORTIZED	102713	INDUSTRIAL FINANSWER-WYOMING-UTAH-2006	OTHER	2,748	0	0	0	0	0	0	0	2,748
1823920	DSR COSTS AMORTIZED	102717	COMMERCIAL SELF-DIRECT-UTAH-2006	OTHER	65	0	0	0	0	0	0	0	65
1823920	DSR COSTS AMORTIZED	102718	INDUSTRIAL SELF-DIRECT-UTAH-2006	OTHER	122	0	0	0	0	0	0	0	122
1823920	DSR COSTS AMORTIZED	102719	RESIDENTIAL NEW CONSTRUCTION-UTAH-2006	OTHER	1,848	0	0	0	0	0	0	0	1,848
1823920	DSR COSTS AMORTIZED	102720	COMMERCIAL FINANSWER EXPRESS-UTAH-2006	OTHER	2,469	0	0	0	0	0	0	0	2,469
1823920	DSR COSTS AMORTIZED	102721	INDUSTRIAL FINANSWER-UTAH-2006	OTHER	536	0	0	0	0	0	0	0	536
1823920	DSR COSTS AMORTIZED	102722	RETROFIT COMMISSIONING PROGRAM -UTAH-200	OTHER	211	0	0	0	0	0	0	0	211
1823920	DSR COSTS AMORTIZED	102723	C&I LIGHTING LOAD CONTROL -UTAH-2006	OTHER	8	0	0	0	0	0	0	0	8
1823920	DSR COSTS AMORTIZED	102725	CALIFORNIA DSM EXPENSE-2006	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	102759	HOME ENERGY EFF INCENTIVE PROG-UTAH-2006	OTHER	241	0	0	0	0	0	0	0	241
1823920	DSR COSTS AMORTIZED	102760	HOME ENERGY EFF INCENTIVE PROG-WA-2006	OTHER	15,240	0	0	0	0	0	0	0	15,240
1823920	DSR COSTS AMORTIZED	102767	DSR COSTS BEING AMORTIZED	OTHER	-44,183	0	0	0	0	0	0	0	-44,183
1823920	DSR COSTS AMORTIZED	102796	DSR COSTS BEING AMORTIZED	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	102819	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	5,982	0	0	0	0	0	0	0	5,982
1823920	DSR COSTS AMORTIZED	102820	AIR CONDITIONING - UTAH - 2007	OTHER	883	0	0	0	0	0	0	0	883
1823920	DSR COSTS AMORTIZED	102821	ENERGY FINANSWER - UTAH - 2007	OTHER	1,952	0	0	0	0	0	0	0	1,952
1823920	DSR COSTS AMORTIZED	102822	INDUSTRIAL FINANSWER - UTAH - 2007	OTHER	3,369	0	0	0	0	0	0	0	3,369
1823920	DSR COSTS AMORTIZED	102823	LOW INCOME - UTAH - 2007	OTHER	117	0	0	0	0	0	0	0	117
1823920	DSR COSTS AMORTIZED	102824	POWER FORWARD - UTAH - 2007	OTHER	50	0	0	0	0	0	0	0	50
1823920	DSR COSTS AMORTIZED	102825	REFRIGERATOR RECYCLING PGM- UTAH - 2007	OTHER	3,399	0	0	0	0	0	0	0	3,399
1823920	DSR COSTS AMORTIZED	102826	COMMERCIAL SELF-DIRECT - UTAH - 2007	OTHER	61	0	0	0	0	0	0	0	61
1823920	DSR COSTS AMORTIZED	102827	INDUSTRIAL SELF-DIRECT - UTAH - 2007	OTHER	108	0	0	0	0	0	0	0	108
1823920	DSR COSTS AMORTIZED	102828	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,936	0	0	0	0	0	0	0	1,936
1823920	DSR COSTS AMORTIZED	102829	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	3,277	0	0	0	0	0	0	0	3,277
1823920	DSR COSTS AMORTIZED	102830	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	968	0	0	0	0	0	0	0	968
1823920	DSR COSTS AMORTIZED	102831	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	187	0	0	0	0	0	0	0	187
1823920	DSR COSTS AMORTIZED	102833	IRRIGATION LOAD CONTROL - UTAH - 2007	OTHER	277	0	0	0	0	0	0	0	277
1823920	DSR COSTS AMORTIZED	102834	HOME ENERGY EFF INCENTIVE PROG - UT 2007	OTHER	3,034	0	0	0	0	0	0	0	3,034
1823920	DSR COSTS AMORTIZED	102883	CALIFORNIA DSM EXPENSE - 2008	CA	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	102906	AC LOAD CONTROL - RESIDENTIAL - UTAH 200	OTHER	7,175	0	0	0	0	0	0	0	7,175
1823920	DSR COSTS AMORTIZED	102907	AIR CONDITIONING - UTAH 2008	OTHER	526	0	0	0	0	0	0	0	526
1823920	DSR COSTS AMORTIZED	102908	ENERGY FINANSWER - UTAH - 2008	OTHER	3,466	0	0	0	0	0	0	0	3,466
1823920	DSR COSTS AMORTIZED	102909	INDUSTRIAL FINANSWER - UTAH - 2008	OTHER	4,289	0	0	0	0	0	0	0	4,289
1823920	DSR COSTS AMORTIZED	102910	LOW INCOME - UTAH 2008	OTHER	127	0	0	0	0	0	0	0	127

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1823920	DSR COSTS AMORTIZED	102911	POWER FORWARD - UTAH - 2008	OTHER	50	0	0	0	0	0	0	0	50
1823920	DSR COSTS AMORTIZED	102912	REFRIGERATOR RECYCLING - UTAH - 2008	OTHER	2,570	0	0	0	0	0	0	0	2,570
1823920	DSR COSTS AMORTIZED	102913	COMMERCIAL SELF DIRECT - UTAH - 2008	OTHER	83	0	0	0	0	0	0	0	83
1823920	DSR COSTS AMORTIZED	102914	INDUSTRIAL SELF DIRECT - UTAH - 2008	OTHER	126	0	0	0	0	0	0	0	126
1823920	DSR COSTS AMORTIZED	102915	RESIDENTIAL NEW CONSTRUCTION - UTAH 2008	OTHER	1,664	0	0	0	0	0	0	0	1,664
1823920	DSR COSTS AMORTIZED	102916	COMMERCIAL FINANSWER EXPRESS - UTAH 2008	OTHER	3,791	0	0	0	0	0	0	0	3,791
1823920	DSR COSTS AMORTIZED	102917	INDUSTRIAL FINANSWER EXPRESS - UTAH 2008	OTHER	1,133	0	0	0	0	0	0	0	1,133
1823920	DSR COSTS AMORTIZED	102918	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	1,053	0	0	0	0	0	0	0	1,053
1823920	DSR COSTS AMORTIZED	102919	C&I LIGHTING LOAD CONTROL - UTAH - 2008	OTHER	4	0	0	0	0	0	0	0	4
1823920	DSR COSTS AMORTIZED	102920	IRRIGATION LOAD CONTROL - UTAH	OTHER	762	0	0	0	0	0	0	0	762
1823920	DSR COSTS AMORTIZED	102921	HOME ENERGY EFF INCENTIVE PROGRAM - UTAH	OTHER	7,817	0	0	0	0	0	0	0	7,817
1823920	DSR COSTS AMORTIZED	102964	CALIFORNIA DSM EXPENSE - 2009	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	102976	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	9,817	0	0	0	0	0	0	0	9,817
1823920	DSR COSTS AMORTIZED	102977	AIR CONDITIONING - UTAH - 2009	OTHER	500	0	0	0	0	0	0	0	500
1823920	DSR COSTS AMORTIZED	102978	ENERGY FINANSWER - UTAH - 2009	OTHER	2,532	0	0	0	0	0	0	0	2,532
1823920	DSR COSTS AMORTIZED	102979	INDUSTRIAL FINANSWER - UTAH - 2009	OTHER	5,215	0	0	0	0	0	0	0	5,215
1823920	DSR COSTS AMORTIZED	102980	LOW INCOME - UTAH - 2009	OTHER	162	0	0	0	0	0	0	0	162
1823920	DSR COSTS AMORTIZED	102981	POWER FORWARD - UTAH - 2009	OTHER	50	0	0	0	0	0	0	0	50
1823920	DSR COSTS AMORTIZED	102982	REFRIGERATOR RECYCLING PGM- UTAH - 2009	OTHER	2,339	0	0	0	0	0	0	0	2,339
1823920	DSR COSTS AMORTIZED	102983	COMMERCIAL SELF-DIRECT - UTAH - 2009	OTHER	53	0	0	0	0	0	0	0	53
1823920	DSR COSTS AMORTIZED	102984	INDUSTRIAL SELF-DIRECT - UTAH - 2009	OTHER	72	0	0	0	0	0	0	0	72
1823920	DSR COSTS AMORTIZED	102985	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,446	0	0	0	0	0	0	0	1,446
1823920	DSR COSTS AMORTIZED	102986	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	3,258	0	0	0	0	0	0	0	3,258
1823920	DSR COSTS AMORTIZED	102987	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	776	0	0	0	0	0	0	0	776
1823920	DSR COSTS AMORTIZED	102988	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	947	0	0	0	0	0	0	0	947
1823920	DSR COSTS AMORTIZED	102990	IRRIGATION LOAD CONTROL - UTAH - 2009	OTHER	2,732	0	0	0	0	0	0	0	2,732
1823920	DSR COSTS AMORTIZED	102991	HOME ENERGY EFF INCENTIVE PROG - UT 2009	OTHER	25,439	0	0	0	0	0	0	0	25,439
1823920	DSR COSTS AMORTIZED	102992	ENERGY FINANSWER - WYOMING PPL - 2009	OTHER	21	0	0	0	0	0	0	0	21
1823920	DSR COSTS AMORTIZED	102993	INDUSTRIAL FINANSWER-WYOMING - PPL 2009	OTHER	96	0	0	0	0	0	0	0	96
1823920	DSR COSTS AMORTIZED	102995	REFRIGERATOR RECYCLING - PPL WYOMING - 2	OTHER	140	0	0	0	0	0	0	0	140
1823920	DSR COSTS AMORTIZED	102996	HOME ENERGY EFF INCENTIVE PRO - PPL WYOM	OTHER	439	0	0	0	0	0	0	0	439
1823920	DSR COSTS AMORTIZED	102997	LOW-INCOME WEATHERIZATION - WYOMING PPL	OTHER	86	0	0	0	0	0	0	0	86
1823920	DSR COSTS AMORTIZED	102998	COMMERCIAL FINANSWER EXPRESS - WY - 2009	OTHER	139	0	0	0	0	0	0	0	139
1823920	DSR COSTS AMORTIZED	102999	INDUSTRIAL FINANSWER EXPRESS - WY - 2009	OTHER	59	0	0	0	0	0	0	0	59
1823920	DSR COSTS AMORTIZED	103000	SELF DIRECT - COMMERCIAL - WY - 2009	OTHER	5	0	0	0	0	0	0	0	5
1823920	DSR COSTS AMORTIZED	103001	SELF DIRECT - INDUSTRIAL - WY - 2009	OTHER	12	0	0	0	0	0	0	0	12
1823920	DSR COSTS AMORTIZED	103003	MAIN CHECK DISB-WIRES/ACH IN CLEAR ACCT	OTHER	2	0	0	0	0	0	0	0	2
1823920	DSR COSTS AMORTIZED	103004	MAIN CHECK DISB-WIRES/ACH OUT CLEAR ACCT	OTHER	2	0	0	0	0	0	0	0	2
1823920	DSR COSTS AMORTIZED	103005	COMMERCIAL FINANSWER EXPRESS Cat 2- WY -	OTHER	236	0	0	0	0	0	0	0	236
1823920	DSR COSTS AMORTIZED	103006	INDUSTRIAL FINANSWER EXPRESS Cat 2- WY -	OTHER	34	0	0	0	0	0	0	0	34
1823920	DSR COSTS AMORTIZED	103007	ENERGY FINANSWER Cat 2 - WY 2009	OTHER	40	0	0	0	0	0	0	0	40

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1823920	DSR COSTS AMORTIZED	103008	INDUSTRIAL FINANSWER Cat 2 -WY 2009	OTHER	34	0	0	0	0	0	0	0	34
1823920	DSR COSTS AMORTIZED	103012	WYOMING REV RECOVERY - SBC OFFSET CAT 1	OTHER	-10,759	0	0	0	0	0	0	0	-10,759
1823920	DSR COSTS AMORTIZED	103013	WYOMING REV RECOVERY - SBC OFFSET CAT 2	OTHER	-10,609	0	0	0	0	0	0	0	-10,609
1823920	DSR COSTS AMORTIZED	103014	WYOMING REV RECOVERY - SBC OFFSET CAT 3	OTHER	-10,192	0	0	0	0	0	0	0	-10,192
1823920	DSR COSTS AMORTIZED	103031	OUTREACH and COMMUNICATIONS - UT 2009	OTHER	571	0	0	0	0	0	0	0	571
1823920	DSR COSTS AMORTIZED	103059	CALIFORNIA DSM EXPENSE - 2010	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103071	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	4,836	0	0	0	0	0	0	0	4,836
1823920	DSR COSTS AMORTIZED	103072	AIR CONDITIONING - UTAH - 2010	OTHER	1,490	0	0	0	0	0	0	0	1,490
1823920	DSR COSTS AMORTIZED	103073	ENERGY FINANSWER - UTAH - 2010	OTHER	3,246	0	0	0	0	0	0	0	3,246
1823920	DSR COSTS AMORTIZED	103074	INDUSTRIAL FINANSWER - UTAH - 2010	OTHER	4,524	0	0	0	0	0	0	0	4,524
1823920	DSR COSTS AMORTIZED	103075	LOW INCOME - UTAH - 2010	OTHER	258	0	0	0	0	0	0	0	258
1823920	DSR COSTS AMORTIZED	103076	POWER FORWARD - UTAH # 2010	OTHER	50	0	0	0	0	0	0	0	50
1823920	DSR COSTS AMORTIZED	103077	REFRIGERATOR RECYCLING PGM- UTAH - 2010	OTHER	2,370	0	0	0	0	0	0	0	2,370
1823920	DSR COSTS AMORTIZED	103078	COMMERCIAL SELF-DIRECT - UTAH - 2010	OTHER	187	0	0	0	0	0	0	0	187
1823920	DSR COSTS AMORTIZED	103079	INDUSTRIAL SELF-DIRECT - UTAH - 2010	OTHER	330	0	0	0	0	0	0	0	330
1823920	DSR COSTS AMORTIZED	103080	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	2,605	0	0	0	0	0	0	0	2,605
1823920	DSR COSTS AMORTIZED	103081	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	4,107	0	0	0	0	0	0	0	4,107
1823920	DSR COSTS AMORTIZED	103082	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,019	0	0	0	0	0	0	0	1,019
1823920	DSR COSTS AMORTIZED	103083	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	986	0	0	0	0	0	0	0	986
1823920	DSR COSTS AMORTIZED	103085	IRRIGATION LOAD CONTROL - UTAH - 2010	OTHER	2,513	0	0	0	0	0	0	0	2,513
1823920	DSR COSTS AMORTIZED	103086	HOME ENERGY EFF INCENTIVE PROG - UT 2010	OTHER	16,876	0	0	0	0	0	0	0	16,876
1823920	DSR COSTS AMORTIZED	103087	OUTREACH and COMMUNICATIONS - UT 2010	OTHER	1,485	0	0	0	0	0	0	0	1,485
1823920	DSR COSTS AMORTIZED	103089	ENERGY FINANSWER-WY-2010 CAT3	OTHER	11	0	0	0	0	0	0	0	11
1823920	DSR COSTS AMORTIZED	103090	INDUSTRIAL FINANSWER-WY-2010 CAT3	OTHER	669	0	0	0	0	0	0	0	669
1823920	DSR COSTS AMORTIZED	103092	REFRIGERATOR RECYCLING-WY -2010 CAT1	OTHER	176	0	0	0	0	0	0	0	176
1823920	DSR COSTS AMORTIZED	103093	HOME ENERGY EFF INCENT PROG Y-2010 CAT1	OTHER	740	0	0	0	0	0	0	0	740
1823920	DSR COSTS AMORTIZED	103094	LOW-INCOME WEATHERZTN - WY 2010 CAT1	OTHER	49	0	0	0	0	0	0	0	49
1823920	DSR COSTS AMORTIZED	103095	COMMERCIAL FINANSWER EXP WY-2010 CAT3	OTHER	65	0	0	0	0	0	0	0	65
1823920	DSR COSTS AMORTIZED	103096	INDUSTRIAL FINANSWER EXP WY-2010 CAT3	OTHER	127	0	0	0	0	0	0	0	127
1823920	DSR COSTS AMORTIZED	103097	SELF DIRECT - COMMERCIAL -WY-2010 CAT3	OTHER	3	0	0	0	0	0	0	0	3
1823920	DSR COSTS AMORTIZED	103098	SELF DIRECT -INDUSTRIAL -WY-2010 CAT3	OTHER	12	0	0	0	0	0	0	0	12
1823920	DSR COSTS AMORTIZED	103099	COMMERCIAL FINANSWER EXP- WY-2010 CAT2	OTHER	587	0	0	0	0	0	0	0	587
1823920	DSR COSTS AMORTIZED	103100	INDUSTRIAL FINAN EXPRESS WY-2010 CAT2	OTHER	55	0	0	0	0	0	0	0	55
1823920	DSR COSTS AMORTIZED	103101	ENERGY FINANSWER -WY 2010 CAT2	OTHER	186	0	0	0	0	0	0	0	186
1823920	DSR COSTS AMORTIZED	103102	INDUSTRIAL FINANSWER -WY 2010 CAT2	OTHER	125	0	0	0	0	0	0	0	125
1823920	DSR COSTS AMORTIZED	103103	Check Disb-Wires/ACH In Clearing - BT	OTHER	1	0	0	0	0	0	0	0	1
1823920	DSR COSTS AMORTIZED	103104	Check Disb-Wires/ACH Out Clearing - BT	OTHER	3	0	0	0	0	0	0	0	3
1823920	DSR COSTS AMORTIZED	103137	Company Initiatives DEI Study- Washingto	OTHER	724	0	0	0	0	0	0	0	724
1823920	DSR COSTS AMORTIZED	103163	Commercial Direct Install - Utah - 2011	OTHER	3	0	0	0	0	0	0	0	3
1823920	DSR COSTS AMORTIZED	103164	Commercial Curtailment - Utah - 2011	OTHER	30	0	0	0	0	0	0	0	30
1823920	DSR COSTS AMORTIZED	103165	Commercial Direct Install - Washington	OTHER	0	0	0	0	0	0	0	0	0

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1823920	DSR COSTS AMORTIZED	103168	CALIFORNIA DSM EXPENSE - 2011	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103169	Commercial Curtailment - Oregon	OTHER	27	0	0	0	0	0	0	0	27
1823920	DSR COSTS AMORTIZED	103181	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	6,498	0	0	0	0	0	0	0	6,498
1823920	DSR COSTS AMORTIZED	103182	AIR CONDITIONING - UTAH - 2011	OTHER	1,305	0	0	0	0	0	0	0	1,305
1823920	DSR COSTS AMORTIZED	103183	ENERGY FINANSWER - UTAH - 2011	OTHER	3,647	0	0	0	0	0	0	0	3,647
1823920	DSR COSTS AMORTIZED	103184	INDUSTRIAL FINANSWER - UTAH - 2011	OTHER	5,016	0	0	0	0	0	0	0	5,016
1823920	DSR COSTS AMORTIZED	103185	LOW INCOME - UTAH - 2011	OTHER	255	0	0	0	0	0	0	0	255
1823920	DSR COSTS AMORTIZED	103186	Power Forward - Utah - 2011	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103187	REFRIGERATOR RECYCLING PGM- UTAH - 2011	OTHER	1,880	0	0	0	0	0	0	0	1,880
1823920	DSR COSTS AMORTIZED	103188	COMMERCIAL SELF-DIRECT - UTAH - 2011	OTHER	126	0	0	0	0	0	0	0	126
1823920	DSR COSTS AMORTIZED	103189	INDUSTRIAL SELF-DIRECT - UTAH - 2011	OTHER	240	0	0	0	0	0	0	0	240
1823920	DSR COSTS AMORTIZED	103190	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	3,071	0	0	0	0	0	0	0	3,071
1823920	DSR COSTS AMORTIZED	103191	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	4,607	0	0	0	0	0	0	0	4,607
1823920	DSR COSTS AMORTIZED	103192	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,233	0	0	0	0	0	0	0	1,233
1823920	DSR COSTS AMORTIZED	103193	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	411	0	0	0	0	0	0	0	411
1823920	DSR COSTS AMORTIZED	103195	IRRIGATION LOAD CONTROL - UTAH - 2011	OTHER	2,513	0	0	0	0	0	0	0	2,513
1823920	DSR COSTS AMORTIZED	103196	HOME ENERGY EFF INCENTIVE PROG - UT 2011	OTHER	11,360	0	0	0	0	0	0	0	11,360
1823920	DSR COSTS AMORTIZED	103197	OUTREACH and COMMUNICATIONS - UT 2011	OTHER	1,437	0	0	0	0	0	0	0	1,437
1823920	DSR COSTS AMORTIZED	103199	ENERGY FINANSWER-WY-2011 CAT3	OTHER	30	0	0	0	0	0	0	0	30
1823920	DSR COSTS AMORTIZED	103200	INDUSTRIAL FINANSWER-WY-2011 CAT3	OTHER	433	0	0	0	0	0	0	0	433
1823920	DSR COSTS AMORTIZED	103202	REFRIGERATOR RECYCLING-WY -2011 CAT1	OTHER	183	0	0	0	0	0	0	0	183
1823920	DSR COSTS AMORTIZED	103203	HOME ENERGY EFF INCENT PROG Y-2011 CAT1	OTHER	1,070	0	0	0	0	0	0	0	1,070
1823920	DSR COSTS AMORTIZED	103204	Low-Income Weatherztn - Wy 2011 CAT1	OTHER	42	0	0	0	0	0	0	0	42
1823920	DSR COSTS AMORTIZED	103205	COMMERCIAL FINANSWER EXP WY-2011 CAT3	OTHER	102	0	0	0	0	0	0	0	102
1823920	DSR COSTS AMORTIZED	103206	INDUSTRIAL FINANSWER EXP WY-2011 CAT3	OTHER	168	0	0	0	0	0	0	0	168
1823920	DSR COSTS AMORTIZED	103207	Self Direct - Commercial -Wy-2011 CAT3	OTHER	6	0	0	0	0	0	0	0	6
1823920	DSR COSTS AMORTIZED	103208	Self Direct -Industrial -Wy-2011 CAT3	OTHER	268	0	0	0	0	0	0	0	268
1823920	DSR COSTS AMORTIZED	103209	COMMERCIAL FINANSWER EXP- WY-2011 CAT2	OTHER	894	0	0	0	0	0	0	0	894
1823920	DSR COSTS AMORTIZED	103210	INDUSTRIAL FINAN EXPRESS WY-2011 CAT2	OTHER	55	0	0	0	0	0	0	0	55
1823920	DSR COSTS AMORTIZED	103211	ENERGY FINANSWER -WY 2011 CAT2	OTHER	51	0	0	0	0	0	0	0	51
1823920	DSR COSTS AMORTIZED	103212	INDUSTRIAL FINANSWER -WY 2011 CAT2	OTHER	98	0	0	0	0	0	0	0	98
1823920	DSR COSTS AMORTIZED	103213	Self Direct - Commercial Wy-2011 CAT2	OTHER	3	0	0	0	0	0	0	0	3
1823920	DSR COSTS AMORTIZED	103214	Self Direct- Industrial Wy-2011 CAT2	OTHER	11	0	0	0	0	0	0	0	11
1823920	DSR COSTS AMORTIZED	103277	OUTREACH & COMM- WATTSMART - EVALUATION	OTHER	1,308	0	0	0	0	0	0	0	1,308
1823920	DSR COSTS AMORTIZED	103280	COMPANY INITIATIVES -PRODUCTION EFFICIEN	OTHER	388	0	0	0	0	0	0	0	388
1823920	DSR COSTS AMORTIZED	103291	Portfolio -WY-2011 Cat4	OTHER	266	0	0	0	0	0	0	0	266
1823920	DSR COSTS AMORTIZED	103292	Portfolio - Washington	OTHER	3,296	0	0	0	0	0	0	0	3,296
1823920	DSR COSTS AMORTIZED	103293	Energy Storage Demonstration Project -UT	OTHER	7	0	0	0	0	0	0	0	7
1823920	DSR COSTS AMORTIZED	103295	Outreach And Communication-WY-2011	OTHER	1	0	0	0	0	0	0	0	1
1823920	DSR COSTS AMORTIZED	103299	AGRICULURAL FINANSWER EXPRESS - UTAH - 2	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103300	AGRICULTURAL FINANSWER EXPRESS - WASHING	OTHER	75	0	0	0	0	0	0	0	75

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1823920	DSR COSTS AMORTIZED	103301	PORTFOLIO -WY-2011 CAT2	OTHER	74	0	0	0	0	0	0	0	74
1823920	DSR COSTS AMORTIZED	103302	PORTFOLIO -WY-2011 CAT3	OTHER	110	0	0	0	0	0	0	0	110
1823920	DSR COSTS AMORTIZED	103308	Home Energy Reporting -OPower -WA 2011	OTHER	1,292	0	0	0	0	0	0	0	1,292
1823920	DSR COSTS AMORTIZED	103311	CALIFORNIA DSM EXPENSE - 2012	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103324	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	5,794	0	0	0	0	0	0	0	5,794
1823920	DSR COSTS AMORTIZED	103325	AIR CONDITIONING - UTAH - 2012	OTHER	1,470	0	0	0	0	0	0	0	1,470
1823920	DSR COSTS AMORTIZED	103326	ENERGY FINANSWER - UTAH - 2012	OTHER	6,899	0	0	0	0	0	0	0	6,899
1823920	DSR COSTS AMORTIZED	103327	INDUSTRIAL FINANSWER - UTAH - 2012	OTHER	2,935	0	0	0	0	0	0	0	2,935
1823920	DSR COSTS AMORTIZED	103328	LOW INCOME - UTAH - 2012	OTHER	177	0	0	0	0	0	0	0	177
1823920	DSR COSTS AMORTIZED	103330	REFRIGERATOR RECYCLING PGM- UTAH - 2012	OTHER	1,474	0	0	0	0	0	0	0	1,474
1823920	DSR COSTS AMORTIZED	103331	COMMERCIAL SELF-DIRECT - UTAH - 2012	OTHER	172	0	0	0	0	0	0	0	172
1823920	DSR COSTS AMORTIZED	103332	INDUSTRIAL SELF-DIRECT - UTAH - 2012	OTHER	429	0	0	0	0	0	0	0	429
1823920	DSR COSTS AMORTIZED	103333	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,943	0	0	0	0	0	0	0	1,943
1823920	DSR COSTS AMORTIZED	103334	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	6,221	0	0	0	0	0	0	0	6,221
1823920	DSR COSTS AMORTIZED	103335	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,280	0	0	0	0	0	0	0	1,280
1823920	DSR COSTS AMORTIZED	103336	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	460	0	0	0	0	0	0	0	460
1823920	DSR COSTS AMORTIZED	103337	IRRIGATION LOAD CONTROL - UTAH - 2012	OTHER	2,097	0	0	0	0	0	0	0	2,097
1823920	DSR COSTS AMORTIZED	103338	HOME ENERGY EFF INCENTIVE PROG - UT 2012	OTHER	11,113	0	0	0	0	0	0	0	11,113
1823920	DSR COSTS AMORTIZED	103339	OUTREACH and COMMUNICATIONS - UT 2012	OTHER	1,836	0	0	0	0	0	0	0	1,836
1823920	DSR COSTS AMORTIZED	103340	COMMERCIAL DIRECT INSTALL - UT 2012	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103341	COMMERCIAL CURTAILMENT - UT 2012	OTHER	-30	0	0	0	0	0	0	0	-30
1823920	DSR COSTS AMORTIZED	103342	ENERGY STORAGE DEMO PROJECT - UT 2012	OTHER	6	0	0	0	0	0	0	0	6
1823920	DSR COSTS AMORTIZED	103343	AGRICULTURAL FINANSWER EXPRESS - UTAH -	OTHER	21	0	0	0	0	0	0	0	21
1823920	DSR COSTS AMORTIZED	103346	HOME ENERGY REPORTING - UT 2012	OTHER	534	0	0	0	0	0	0	0	534
1823920	DSR COSTS AMORTIZED	103347	ENERGY FINANSWER-WY-2012 CAT3	OTHER	20	0	0	0	0	0	0	0	20
1823920	DSR COSTS AMORTIZED	103348	INDUSTRIAL FINANSWER-WY-2012 CAT3	OTHER	606	0	0	0	0	0	0	0	606
1823920	DSR COSTS AMORTIZED	103349	REFRIGERATOR RECYCLING-WY -2012 CAT1	OTHER	169	0	0	0	0	0	0	0	169
1823920	DSR COSTS AMORTIZED	103350	HOME ENERGY EFF INCENT PROG Y-2012 CAT1	OTHER	904	0	0	0	0	0	0	0	904
1823920	DSR COSTS AMORTIZED	103351	LOW-INCOME WEATHERZTN - WY 2012 CAT1	OTHER	31	0	0	0	0	0	0	0	31
1823920	DSR COSTS AMORTIZED	103352	COMMERCIAL FINANSWER EXP WY-2012 CAT3	OTHER	143	0	0	0	0	0	0	0	143
1823920	DSR COSTS AMORTIZED	103353	INDUSTRIAL FINANSWER EXP WY-2012 CAT3	OTHER	170	0	0	0	0	0	0	0	170
1823920	DSR COSTS AMORTIZED	103354	SELF DIRECT - COMMERCIAL -WY-2012 CAT3	OTHER	4	0	0	0	0	0	0	0	4
1823920	DSR COSTS AMORTIZED	103355	SELF DIRECT -INDUSTRIAL -WY-2012 CAT3	OTHER	60	0	0	0	0	0	0	0	60
1823920	DSR COSTS AMORTIZED	103356	COMMERCIAL FINANSWER EXP- WY-2012 CAT2	OTHER	1,203	0	0	0	0	0	0	0	1,203
1823920	DSR COSTS AMORTIZED	103357	INDUSTRIAL FINAN EXPRESS WY-2012 CAT2	OTHER	58	0	0	0	0	0	0	0	58
1823920	DSR COSTS AMORTIZED	103358	ENERGY FINANSWER -WY 2012 CAT2	OTHER	59	0	0	0	0	0	0	0	59
1823920	DSR COSTS AMORTIZED	103359	INDUSTRIAL FINANSWER -WY 2012 CAT2	OTHER	205	0	0	0	0	0	0	0	205
1823920	DSR COSTS AMORTIZED	103360	SELF DIRECT - COMMERCIAL WY-2012 CAT2	OTHER	1	0	0	0	0	0	0	0	1
1823920	DSR COSTS AMORTIZED	103361	SELF DIRECT- INDUSTRIAL WY-2012 CAT2	OTHER	1	0	0	0	0	0	0	0	1
1823920	DSR COSTS AMORTIZED	103363	PORTFOLIO WY-2012 CAT1	OTHER	33	0	0	0	0	0	0	0	33
1823920	DSR COSTS AMORTIZED	103364	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	155	0	0	0	0	0	0	0	155

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1823920	DSR COSTS AMORTIZED	103365	AGRICULURAL FINANSWER EXP WY-2012 CAT2	OTHER	1	0	0	0	0	0	0	0	1
1823920	DSR COSTS AMORTIZED	103366	AGRICULURAL FINANSWER EXP WY-2012 CAT3	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103367	PORTFOLIO WY-2012 CAT2	OTHER	35	0	0	0	0	0	0	0	35
1823920	DSR COSTS AMORTIZED	103368	PORTFOLIO WY-2012 CAT3	OTHER	30	0	0	0	0	0	0	0	30
1823920	DSR COSTS AMORTIZED	103369	COMMERCIAL CURTAILMENT - OR 2012	OTHER	-27	0	0	0	0	0	0	0	-27
1823920	DSR COSTS AMORTIZED	103493	U.of Utah Student Energy Sponsorship- UT	OTHER	8	0	0	0	0	0	0	0	8
1823920	DSR COSTS AMORTIZED	103496	PORTFOLIO - IDAHO	OTHER	2	0	0	0	0	0	0	0	2
1823920	DSR COSTS AMORTIZED	103497	PORTFOLIO - UTAH	OTHER	42	0	0	0	0	0	0	0	42
1823920	DSR COSTS AMORTIZED	103623	CALIFORNIA DSM EXPENSE - 2013	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103646	PORTFOLIO - IDAHO 2013	OTHER	38	0	0	0	0	0	0	0	38
1823920	DSR COSTS AMORTIZED	103647	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	10,293	0	0	0	0	0	0	0	10,293
1823920	DSR COSTS AMORTIZED	103648	AIR CONDITIONING - UTAH - 2013	OTHER	66	0	0	0	0	0	0	0	66
1823920	DSR COSTS AMORTIZED	103649	ENERGY FINANSWER - UTAH - 2013	OTHER	1,445	0	0	0	0	0	0	0	1,445
1823920	DSR COSTS AMORTIZED	103650	INDUSTRIAL FINANSWER - UTAH - 2013	OTHER	2,168	0	0	0	0	0	0	0	2,168
1823920	DSR COSTS AMORTIZED	103651	LOW INCOME - UTAH - 2013	OTHER	120	0	0	0	0	0	0	0	120
1823920	DSR COSTS AMORTIZED	103653	REFRIGERATOR RECYCLING PGM- UTAH - 2013	OTHER	1,544	0	0	0	0	0	0	0	1,544
1823920	DSR COSTS AMORTIZED	103654	COMMERCIAL SELF-DIRECT - UTAH - 2013	OTHER	116	0	0	0	0	0	0	0	116
1823920	DSR COSTS AMORTIZED	103655	INDUSTRIAL SELF-DIRECT - UTAH - 2013	OTHER	319	0	0	0	0	0	0	0	319
1823920	DSR COSTS AMORTIZED	103656	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,314	0	0	0	0	0	0	0	1,314
1823920	DSR COSTS AMORTIZED	103657	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	8,290	0	0	0	0	0	0	0	8,290
1823920	DSR COSTS AMORTIZED	103658	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,444	0	0	0	0	0	0	0	1,444
1823920	DSR COSTS AMORTIZED	103660	IRRIGATION LOAD CONTROL - UTAH - 2013	OTHER	807	0	0	0	0	0	0	0	807
1823920	DSR COSTS AMORTIZED	103661	HOME ENERGY EFF INCENTIVE PROG - UT 2013	OTHER	20,269	0	0	0	0	0	0	0	20,269
1823920	DSR COSTS AMORTIZED	103662	OUTREACH and COMMUNICATIONS - UT 2013	OTHER	1,406	0	0	0	0	0	0	0	1,406
1823920	DSR COSTS AMORTIZED	103666	AGRICULTURAL FINANSWER EXPRESS - UTAH -	OTHER	70	0	0	0	0	0	0	0	70
1823920	DSR COSTS AMORTIZED	103671	HOME ENERGY REPORTING - UT 2013	OTHER	765	0	0	0	0	0	0	0	765
1823920	DSR COSTS AMORTIZED	103673	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	135	0	0	0	0	0	0	0	135
1823920	DSR COSTS AMORTIZED	103675	ENERGY FINANSWER-WY-2013 CAT3	OTHER	27	0	0	0	0	0	0	0	27
1823920	DSR COSTS AMORTIZED	103676	INDUSTRIAL FINANSWER-WY-2013 CAT3	OTHER	985	0	0	0	0	0	0	0	985
1823920	DSR COSTS AMORTIZED	103677	REFRIGERATOR RECYCLING-WY -2013 CAT1	OTHER	130	0	0	0	0	0	0	0	130
1823920	DSR COSTS AMORTIZED	103678	HOME ENERGY EFF INCENT PROG Y-2013 CAT1	OTHER	884	0	0	0	0	0	0	0	884
1823920	DSR COSTS AMORTIZED	103679	LOW-INCOME WEATHERZTN - WY 2013 CAT1	OTHER	41	0	0	0	0	0	0	0	41
1823920	DSR COSTS AMORTIZED	103680	COMMERCIAL FINANSWER EXP WY-2013 CAT3	OTHER	424	0	0	0	0	0	0	0	424
1823920	DSR COSTS AMORTIZED	103681	INDUSTRIAL FINANSWER EXP WY-2013 CAT3	OTHER	169	0	0	0	0	0	0	0	169
1823920	DSR COSTS AMORTIZED	103682	SELF DIRECT - COMMERCIAL -WY-2013 CAT3	OTHER	2	0	0	0	0	0	0	0	2
1823920	DSR COSTS AMORTIZED	103683	SELF DIRECT -INDUSTRIAL -WY-2013 CAT3	OTHER	9	0	0	0	0	0	0	0	9
1823920	DSR COSTS AMORTIZED	103684	COMMERCIAL FINANSWER EXP- WY-2013 CAT2	OTHER	1,234	0	0	0	0	0	0	0	1,234
1823920	DSR COSTS AMORTIZED	103685	INDUSTRIAL FINAN EXPRESS WY-2013 CAT2	OTHER	85	0	0	0	0	0	0	0	85
1823920	DSR COSTS AMORTIZED	103686	ENERGY FINANSWER -WY 2013 CAT2	OTHER	26	0	0	0	0	0	0	0	26
1823920	DSR COSTS AMORTIZED	103687	INDUSTRIAL FINANSWER -WY 2013 CAT2	OTHER	58	0	0	0	0	0	0	0	58
1823920	DSR COSTS AMORTIZED	103688	SELF DIRECT - COMMERCIAL WY-2013 CAT2	OTHER	2	0	0	0	0	0	0	0	2

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1823920	DSR COSTS AMORTIZED	103689	SELF DIRECT- INDUSTRIAL WY-2013 CAT2	OTHER	8	0	0	0	0	0	0	0	8
1823920	DSR COSTS AMORTIZED	103690	PORTFOLIO WY-2013 CAT1	OTHER	130	0	0	0	0	0	0	0	130
1823920	DSR COSTS AMORTIZED	103691	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	178	0	0	0	0	0	0	0	178
1823920	DSR COSTS AMORTIZED	103692	AGRICULTURAL FINANSWER EXP WY-2013 CAT2	OTHER	10	0	0	0	0	0	0	0	10
1823920	DSR COSTS AMORTIZED	103693	AGRICULURAL FINANSWER EXP WY-2013 CAT3	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103694	PORTFOLIO WY-2013 CAT2	OTHER	38	0	0	0	0	0	0	0	38
1823920	DSR COSTS AMORTIZED	103695	PORTFOLIO WY-2013 CAT3	OTHER	26	0	0	0	0	0	0	0	26
1823920	DSR COSTS AMORTIZED	103700	PORTFOLIO - UTAH 2013	OTHER	435	0	0	0	0	0	0	0	435
1823920	DSR COSTS AMORTIZED	103701	U.of Utah Student Energy Sponsorship- UT	OTHER	2	0	0	0	0	0	0	0	2
1823920	DSR COSTS AMORTIZED	103732	COMMERCIAL (WSB) WATTSMART BUSINESS - UT	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103734	INDUSTRIAL (WSB) WATTSMART BUSINESS - UT	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103735	WSB - WATTSMART BUSINESS - UT- 2013	OTHER	12	0	0	0	0	0	0	0	12
1823920	DSR COSTS AMORTIZED	103740	COMMERCIAL (WSB) WATTSMART BUSINESS - WA	OTHER	5,435	0	0	0	0	0	0	0	5,435
1823920	DSR COSTS AMORTIZED	103741	INDUSTRIAL WATTSMART BUSINESS - WA-2013	OTHER	6,233	0	0	0	0	0	0	0	6,233
1823920	DSR COSTS AMORTIZED	103742	WSB - WATTSMART BUSINESS - WA- 2013	OTHER	4,049	0	0	0	0	0	0	0	4,049
1823920	DSR COSTS AMORTIZED	103743	AGRICULTURAL (WSB) WATTSMART BUSINESS -	OTHER	306	0	0	0	0	0	0	0	306
1823920	DSR COSTS AMORTIZED	103745	CALIFORNIA DSM EXPENSE - 2014	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103754	PORTFOLIO - IDAHO 2014	OTHER	30	0	0	0	0	0	0	0	30
1823920	DSR COSTS AMORTIZED	103756	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	24,564	0	0	0	0	0	0	0	24,564
1823920	DSR COSTS AMORTIZED	103757	AGRICULURAL FINANSWER EXPRESS - UTAH - 2	OTHER	1	0	0	0	0	0	0	0	1
1823920	DSR COSTS AMORTIZED	103758	AIR CONDITIONING - UTAH - 2014	OTHER	1	0	0	0	0	0	0	0	1
1823920	DSR COSTS AMORTIZED	103759	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	401	0	0	0	0	0	0	0	401
1823920	DSR COSTS AMORTIZED	103760	ENERGY FINANSWER - UTAH - 2014	OTHER	37	0	0	0	0	0	0	0	37
1823920	DSR COSTS AMORTIZED	103761	HOME ENERGY EFF INCENTIVE PROG - UT 2014	OTHER	24,908	0	0	0	0	0	0	0	24,908
1823920	DSR COSTS AMORTIZED	103762	HOME ENERGY REPORTING - UT 2014	OTHER	1,630	0	0	0	0	0	0	0	1,630
1823920	DSR COSTS AMORTIZED	103763	INDUSTRIAL FINANSWER - UTAH - 2014	OTHER	60	0	0	0	0	0	0	0	60
1823920	DSR COSTS AMORTIZED	103764	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	144	0	0	0	0	0	0	0	144
1823920	DSR COSTS AMORTIZED	103765	IRRIGATION LOAD CONTROL - UTAH - 2014	OTHER	597	0	0	0	0	0	0	0	597
1823920	DSR COSTS AMORTIZED	103766	LOW INCOME - UTAH - 2014	OTHER	170	0	0	0	0	0	0	0	170
1823920	DSR COSTS AMORTIZED	103767	OUTREACH and COMMUNICATIONS - UT 2014	OTHER	1,585	0	0	0	0	0	0	0	1,585
1823920	DSR COSTS AMORTIZED	103768	PORTFOLIO - UTAH 2014	OTHER	242	0	0	0	0	0	0	0	242
1823920	DSR COSTS AMORTIZED	103769	REFRIGERATOR RECYCLING PGM- UTAH - 2014	OTHER	1,762	0	0	0	0	0	0	0	1,762
1823920	DSR COSTS AMORTIZED	103770	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,203	0	0	0	0	0	0	0	1,203
1823920	DSR COSTS AMORTIZED	103771	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	1	0	0	0	0	0	0	0	1
1823920	DSR COSTS AMORTIZED	103772	COMMERCIAL SELF-DIRECT - UTAH - 2014	OTHER	29	0	0	0	0	0	0	0	29
1823920	DSR COSTS AMORTIZED	103773	INDUSTRIAL SELF-DIRECT - UTAH - 2014	OTHER	53	0	0	0	0	0	0	0	53
1823920	DSR COSTS AMORTIZED	103774	COMMERCIAL (WSB) WATTSMART BUS - UT- 201	OTHER	12,239	0	0	0	0	0	0	0	12,239
1823920	DSR COSTS AMORTIZED	103775	INDUSTRIAL (WSB) WATTSMART BUS- UT- 2014	OTHER	6,640	0	0	0	0	0	0	0	6,640
1823920	DSR COSTS AMORTIZED	103776	WSB - WATTSMART BUS- UT- 2014	OTHER	3,636	0	0	0	0	0	0	0	3,636
1823920	DSR COSTS AMORTIZED	103777	AGRICULTURAL (WSB) WATTSMART BUS- UT- 20	OTHER	161	0	0	0	0	0	0	0	161
1823920	DSR COSTS AMORTIZED	103778	U.of Utah Student Energy Sponsorship- UT	OTHER	5	0	0	0	0	0	0	0	5

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1823920	DSR COSTS AMORTIZED	103779	AGRICULURAL FINANSWER EXP WY-2014 CAT2	OTHER	4	0	0	0	0	0	0	0	4
1823920	DSR COSTS AMORTIZED	103780	AGRICULURAL FINANSWER EXP WY-2014 CAT3	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103781	COMMERCIAL FINANSWER EXP- WY-2014 CAT2	OTHER	1,178	0	0	0	0	0	0	0	1,178
1823920	DSR COSTS AMORTIZED	103782	COMMERCIAL FINANSWER EXP WY-2014 CAT3	OTHER	255	0	0	0	0	0	0	0	255
1823920	DSR COSTS AMORTIZED	103783	ENERGY FINANSWER -WY 2014 CAT2	OTHER	32	0	0	0	0	0	0	0	32
1823920	DSR COSTS AMORTIZED	103784	ENERGY FINANSWER-WY-2014 CAT3	OTHER	71	0	0	0	0	0	0	0	71
1823920	DSR COSTS AMORTIZED	103785	HOME ENERGY EFF INCENT PROG Y-2014 CAT1	OTHER	1,183	0	0	0	0	0	0	0	1,183
1823920	DSR COSTS AMORTIZED	103786	INDUSTRIAL FINANSWER -WY 2014 CAT2	OTHER	95	0	0	0	0	0	0	0	95
1823920	DSR COSTS AMORTIZED	103787	INDUSTRIAL FINANSWER-WY-2014 CAT3	OTHER	356	0	0	0	0	0	0	0	356
1823920	DSR COSTS AMORTIZED	103788	INDUSTRIAL FINAN EXPRESS WY-2014 CAT2	OTHER	136	0	0	0	0	0	0	0	136
1823920	DSR COSTS AMORTIZED	103789	INDUSTRIAL FINANSWER EXP WY-2014 CAT3	OTHER	203	0	0	0	0	0	0	0	203
1823920	DSR COSTS AMORTIZED	103790	LOW-INCOME WEATHERZTN - WY 2014 CAT1	OTHER	30	0	0	0	0	0	0	0	30
1823920	DSR COSTS AMORTIZED	103791	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	157	0	0	0	0	0	0	0	157
1823920	DSR COSTS AMORTIZED	103792	PORTFOLIO WY-2014 CAT1	OTHER	63	0	0	0	0	0	0	0	63
1823920	DSR COSTS AMORTIZED	103793	PORTFOLIO WY-2014 CAT2	OTHER	147	0	0	0	0	0	0	0	147
1823920	DSR COSTS AMORTIZED	103794	PORTFOLIO WY-2014 CAT3	OTHER	258	0	0	0	0	0	0	0	258
1823920	DSR COSTS AMORTIZED	103795	REFRIGERATOR RECYCLING-WY -2014 CAT1	OTHER	159	0	0	0	0	0	0	0	159
1823920	DSR COSTS AMORTIZED	103796	SELF DIRECT - COMMERCIAL WY-2014 CAT2	OTHER	2	0	0	0	0	0	0	0	2
1823920	DSR COSTS AMORTIZED	103797	SELF DIRECT - COMMERCIAL -WY-2014 CAT3	OTHER	2	0	0	0	0	0	0	0	2
1823920	DSR COSTS AMORTIZED	103798	SELF DIRECT- INDUSTRIAL WY-2014 CAT2	OTHER	2	0	0	0	0	0	0	0	2
1823920	DSR COSTS AMORTIZED	103799	SELF DIRECT -INDUSTRIAL -WY-2014 CAT3	OTHER	198	0	0	0	0	0	0	0	198
1823920	DSR COSTS AMORTIZED	103805	WSB - WATTSMART BUSINESS - CA- 2014	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103808	WSB - WATTSMART BUSINESS - ID- 2014	OTHER	32	0	0	0	0	0	0	0	32
1823920	DSR COSTS AMORTIZED	103809	WSB Small Business Comm - ID-2014	OTHER	11	0	0	0	0	0	0	0	11
1823920	DSR COSTS AMORTIZED	103810	WSB Small Business Ind - ID 2014	OTHER	8	0	0	0	0	0	0	0	8
1823920	DSR COSTS AMORTIZED	103811	WSB - Wattsmart Business - WY Cat 2- 201	OTHER	26	0	0	0	0	0	0	0	26
1823920	DSR COSTS AMORTIZED	103812	WSB - Small Business Comm - WY Cat2 -201	OTHER	7	0	0	0	0	0	0	0	7
1823920	DSR COSTS AMORTIZED	103813	WBS Small Business Ind - WY Cat2-2014	OTHER	5	0	0	0	0	0	0	0	5
1823920	DSR COSTS AMORTIZED	103814	WSB Small Business Comm- UT-2014	OTHER	1,635	0	0	0	0	0	0	0	1,635
1823920	DSR COSTS AMORTIZED	103815	WBS Small Business Ind- UT-2014	OTHER	23	0	0	0	0	0	0	0	23
1823920	DSR COSTS AMORTIZED	103816	WSB Small Business Comm- WA-2014	OTHER	557	0	0	0	0	0	0	0	557
1823920	DSR COSTS AMORTIZED	103817	WBS Small Business Ind- WA-2014	OTHER	46	0	0	0	0	0	0	0	46
1823920	DSR COSTS AMORTIZED	103834	HOME ENERGY REPORTING - ID 2014	OTHER	20	0	0	0	0	0	0	0	20
1823920	DSR COSTS AMORTIZED	103835	HOME ENERGY REPORTING - WY 2014	OTHER	23	0	0	0	0	0	0	0	23
1823920	DSR COSTS AMORTIZED	103845	REFRIGERATOR RECYCLING COMM - WASHINGTON	OTHER	1	0	0	0	0	0	0	0	1
1823920	DSR COSTS AMORTIZED	103856	WSB Wattsmart Business Agric - ID-2014	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103858	WSB Wattsmart Business Comm- WY Cat3 -20	OTHER	8	0	0	0	0	0	0	0	8
1823920	DSR COSTS AMORTIZED	103859	WBS Wattsmart Business Ind- WY Cat2-2014	OTHER	26	0	0	0	0	0	0	0	26
1823920	DSR COSTS AMORTIZED	103860	WSB- Wattsmart Business- WY Cat 3- 2014	OTHER	5	0	0	0	0	0	0	0	5
1823920	DSR COSTS AMORTIZED	103862	OUTREACH AND COMMUNICATION ID-2014	OTHER	5	0	0	0	0	0	0	0	5
1823920	DSR COSTS AMORTIZED	103865	CALIFORNIA DSM EXPENSE - 2015	OTHER	0	0	0	0	0	0	0	0	0

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1823920	DSR COSTS AMORTIZED	103874	PORTFOLIO - IDAHO 2015	OTHER	23	0	0	0	0	0	0	0	23
1823920	DSR COSTS AMORTIZED	103876	WSB - WATTSMART BUSINESS - ID- 2015	OTHER	410	0	0	0	0	0	0	0	410
1823920	DSR COSTS AMORTIZED	103877	WSB Small Business Comm - ID-2015	OTHER	1,345	0	0	0	0	0	0	0	1,345
1823920	DSR COSTS AMORTIZED	103878	WSB Small Business Ind - ID 2015	OTHER	264	0	0	0	0	0	0	0	264
1823920	DSR COSTS AMORTIZED	103879	HOME ENERGY REPORTING - ID 2015	OTHER	136	0	0	0	0	0	0	0	136
1823920	DSR COSTS AMORTIZED	103880	WSB Wattsmart Business Agric - ID-2015	OTHER	227	0	0	0	0	0	0	0	227
1823920	DSR COSTS AMORTIZED	103881	OUTREACH AND COMMUNICATION ID-2015	OTHER	153	0	0	0	0	0	0	0	153
1823920	DSR COSTS AMORTIZED	103882	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	4,174	0	0	0	0	0	0	0	4,174
1823920	DSR COSTS AMORTIZED	103887	HOME ENERGY EFF INCENTIVE PROG - UT 2015	OTHER	18,922	0	0	0	0	0	0	0	18,922
1823920	DSR COSTS AMORTIZED	103888	HOME ENERGY REPORTING - UT 2015	OTHER	2,878	0	0	0	0	0	0	0	2,878
1823920	DSR COSTS AMORTIZED	103891	IRRIGATION LOAD CONTROL - UTAH - 2015	OTHER	476	0	0	0	0	0	0	0	476
1823920	DSR COSTS AMORTIZED	103892	LOW INCOME - UTAH - 2015	OTHER	64	0	0	0	0	0	0	0	64
1823920	DSR COSTS AMORTIZED	103893	OUTREACH and COMMUNICATIONS - UT 2015	OTHER	1,611	0	0	0	0	0	0	0	1,611
1823920	DSR COSTS AMORTIZED	103894	PORTFOLIO - UTAH 2015	OTHER	370	0	0	0	0	0	0	0	370
1823920	DSR COSTS AMORTIZED	103895	REFRIGERATOR RECYCLING PGM- UTAH - 2015	OTHER	1,125	0	0	0	0	0	0	0	1,125
1823920	DSR COSTS AMORTIZED	103896	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,890	0	0	0	0	0	0	0	1,890
1823920	DSR COSTS AMORTIZED	103900	COMMERCIAL (WSB) WATTSMART BUS - UT- 201	OTHER	15,213	0	0	0	0	0	0	0	15,213
1823920	DSR COSTS AMORTIZED	103901	INDUSTRIAL (WSB) WATTSMART BUS- UT- 2015	OTHER	6,316	0	0	0	0	0	0	0	6,316
1823920	DSR COSTS AMORTIZED	103902	WSB - WATTSMART BUS- UT- 2015	OTHER	4,777	0	0	0	0	0	0	0	4,777
1823920	DSR COSTS AMORTIZED	103903	AGRICULTURAL (WSB) WATTSMART BUS- UT- 20	OTHER	257	0	0	0	0	0	0	0	257
1823920	DSR COSTS AMORTIZED	103904	U.of Utah Student Energy Sponsorship- UT	OTHER	6	0	0	0	0	0	0	0	6
1823920	DSR COSTS AMORTIZED	103905	WSB Small Business Comm- UT-2015	OTHER	3,896	0	0	0	0	0	0	0	3,896
1823920	DSR COSTS AMORTIZED	103906	WBS Small Business Ind- UT-2015	OTHER	262	0	0	0	0	0	0	0	262
1823920	DSR COSTS AMORTIZED	103907	AGRICULURAL FINANSWER EXP WY-2015 CAT2	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103909	COMMERCIAL FINANSWER EXP- WY-2015 CAT2	OTHER	97	0	0	0	0	0	0	0	97
1823920	DSR COSTS AMORTIZED	103910	COMMERCIAL FINANSWER EXP WY-2015 CAT3	OTHER	54	0	0	0	0	0	0	0	54
1823920	DSR COSTS AMORTIZED	103911	ENERGY FINANSWER -WY 2015 CAT2	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103912	ENERGY FINANSWER-WY-2015 CAT3	OTHER	43	0	0	0	0	0	0	0	43
1823920	DSR COSTS AMORTIZED	103913	HOME ENERGY EFF INCENT PROG Y-2015 CAT1	OTHER	1,207	0	0	0	0	0	0	0	1,207
1823920	DSR COSTS AMORTIZED	103914	INDUSTRIAL FINANSWER -WY 2015 CAT2	OTHER	2	0	0	0	0	0	0	0	2
1823920	DSR COSTS AMORTIZED	103915	INDUSTRIAL FINANSWER-WY-2015 CAT3	OTHER	85	0	0	0	0	0	0	0	85
1823920	DSR COSTS AMORTIZED	103916	INDUSTRIAL FINAN EXPRESS WY-2015 CAT2	OTHER	9	0	0	0	0	0	0	0	9
1823920	DSR COSTS AMORTIZED	103917	INDUSTRIAL FINANSWER EXP WY-2015 CAT3	OTHER	3	0	0	0	0	0	0	0	3
1823920	DSR COSTS AMORTIZED	103918	LOW-INCOME WEATHERZTN - WY 2015 CAT1	OTHER	30	0	0	0	0	0	0	0	30
1823920	DSR COSTS AMORTIZED	103919	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	121	0	0	0	0	0	0	0	121
1823920	DSR COSTS AMORTIZED	103920	PORTFOLIO WY-2015 CAT1	OTHER	71	0	0	0	0	0	0	0	71
1823920	DSR COSTS AMORTIZED	103921	PORTFOLIO WY-2015 CAT2	OTHER	29	0	0	0	0	0	0	0	29
1823920	DSR COSTS AMORTIZED	103922	PORTFOLIO WY-2015 CAT3	OTHER	47	0	0	0	0	0	0	0	47
1823920	DSR COSTS AMORTIZED	103923	REFRIGERATOR RECYCLING-WY -2015 CAT1	OTHER	99	0	0	0	0	0	0	0	99
1823920	DSR COSTS AMORTIZED	103925	SELF DIRECT - COMMERCIAL -WY-2015 CAT3	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103927	SELF DIRECT -INDUSTRIAL -WY-2015 CAT3	OTHER	1	0	0	0	0	0	0	0	1

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1823920	DSR COSTS AMORTIZED	103928	WSB - Wattsmart Business - WY Cat 2- 201	OTHER	639	0	0	0	0	0	0	0	639
1823920	DSR COSTS AMORTIZED	103929	WSB - Small Business Comm - WY Cat2 -201	OTHER	1,071	0	0	0	0	0	0	0	1,071
1823920	DSR COSTS AMORTIZED	103930	WBS- Wattsmart Business Ind -WY Cat2-201	OTHER	286	0	0	0	0	0	0	0	286
1823920	DSR COSTS AMORTIZED	103931	HOME ENERGY REPORTING - WY 2015	OTHER	139	0	0	0	0	0	0	0	139
1823920	DSR COSTS AMORTIZED	103932	WSB- Wattsmart Business- WY Cat 3- 2015	OTHER	178	0	0	0	0	0	0	0	178
1823920	DSR COSTS AMORTIZED	103933	REFRIG RECYCLE COMM -WY 2015 CAT2	OTHER	1	0	0	0	0	0	0	0	1
1823920	DSR COSTS AMORTIZED	103934	REFRIG RECYCLE COMM -WY 2015 CAT3	OTHER	1	0	0	0	0	0	0	0	1
1823920	DSR COSTS AMORTIZED	103935	WSB Wattsmart Business Comm- WY Cat3 -20	OTHER	381	0	0	0	0	0	0	0	381
1823920	DSR COSTS AMORTIZED	103936	WBS- Wattsmart Bus Ind- WY Cat3-2015	OTHER	1,487	0	0	0	0	0	0	0	1,487
1823920	DSR COSTS AMORTIZED	103937	WSB- Wattsmart Business Agric- WY Cat2 -	OTHER	18	0	0	0	0	0	0	0	18
1823920	DSR COSTS AMORTIZED	103938	WSB- Wattsmart Business Agric- WY Cat3 -	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	103959	COMMERCIAL ENERGY REPORTS-SMB -UT 2015	OTHER	3	0	0	0	0	0	0	0	3
1823920	DSR COSTS AMORTIZED	103962	Portfolio - EM&V C&I - ID- 2015	OTHER	2	0	0	0	0	0	0	0	2
1823920	DSR COSTS AMORTIZED	103963	Portfolio - EM&V RES - ID- 2015	OTHER	41	0	0	0	0	0	0	0	41
1823920	DSR COSTS AMORTIZED	104013	CALIFORNIA DSM EXPENSE - 2016	OTHER	0	0	0	0	0	0	0	0	0
1823920	DSR COSTS AMORTIZED	104015	HOME ENERGY REPORTING - ID 2016	OTHER	94	0	0	0	0	0	0	0	94
1823920	DSR COSTS AMORTIZED	104018	OUTREACH AND COMMUNICATION ID-2016	OTHER	98	0	0	0	0	0	0	0	98
1823920	DSR COSTS AMORTIZED	104019	PORTFOLIO - IDAHO 2016	OTHER	6	0	0	0	0	0	0	0	6
1823920	DSR COSTS AMORTIZED	104020	Portfolio - EM&V C&I - ID- 2016	OTHER	166	0	0	0	0	0	0	0	166
1823920	DSR COSTS AMORTIZED	104021	Portfolio - EM&V RES - ID- 2016	OTHER	165	0	0	0	0	0	0	0	165
1823920	DSR COSTS AMORTIZED	104023	WSB Small Business Comm - ID-2016	OTHER	1,392	0	0	0	0	0	0	0	1,392
1823920	DSR COSTS AMORTIZED	104024	WSB Small Business Ind - ID 2016	OTHER	220	0	0	0	0	0	0	0	220
1823920	DSR COSTS AMORTIZED	104025	WSB - WATTSMART BUSINESS - ID- 2016	OTHER	607	0	0	0	0	0	0	0	607
1823920	DSR COSTS AMORTIZED	104026	WSB Wattsmart Business Agric - ID-2016	OTHER	311	0	0	0	0	0	0	0	311
1823920	DSR COSTS AMORTIZED	104027	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	4,957	0	0	0	0	0	0	0	4,957
1823920	DSR COSTS AMORTIZED	104029	HOME ENERGY EFF INCENTIVE PROG - UT 2016	OTHER	12,572	0	0	0	0	0	0	0	12,572
1823920	DSR COSTS AMORTIZED	104030	HOME ENERGY REPORTING - UT 2016	OTHER	2,335	0	0	0	0	0	0	0	2,335
1823920	DSR COSTS AMORTIZED	104031	IRRIGATION LOAD CONTROL - UTAH - 2016	OTHER	430	0	0	0	0	0	0	0	430
1823920	DSR COSTS AMORTIZED	104032	LOW INCOME - UTAH - 2016	OTHER	59	0	0	0	0	0	0	0	59
1823920	DSR COSTS AMORTIZED	104033	OUTREACH and COMMUNICATIONS - UT 2016	OTHER	1,313	0	0	0	0	0	0	0	1,313
1823920	DSR COSTS AMORTIZED	104034	PORTFOLIO - UTAH 2016	OTHER	164	0	0	0	0	0	0	0	164
1823920	DSR COSTS AMORTIZED	104035	REFRIGERATOR RECYCLING PGM- UTAH - 2016	OTHER	182	0	0	0	0	0	0	0	182
1823920	DSR COSTS AMORTIZED	104036	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,565	0	0	0	0	0	0	0	1,565
1823920	DSR COSTS AMORTIZED	104037	COMMERCIAL (WSB) WATTSMART BUS - UT- 201	OTHER	20,226	0	0	0	0	0	0	0	20,226
1823920	DSR COSTS AMORTIZED	104038	INDUSTRIAL (WSB) WATTSMART BUS- UT- 2016	OTHER	10,333	0	0	0	0	0	0	0	10,333
1823920	DSR COSTS AMORTIZED	104039	WSB Small Business Comm- UT-2016	OTHER	114	0	0	0	0	0	0	0	114
1823920	DSR COSTS AMORTIZED	104041	WSB - WATTSMART BUS- UT- 2016	OTHER	5,308	0	0	0	0	0	0	0	5,308
1823920	DSR COSTS AMORTIZED	104042	AGRICULTURAL (WSB) WATTSMART BUS- UT- 20	OTHER	1,099	0	0	0	0	0	0	0	1,099
1823920	DSR COSTS AMORTIZED	104043	U.of Utah Student Energy Sponsorship- UT	OTHER	5	0	0	0	0	0	0	0	5
1823920	DSR COSTS AMORTIZED	104044	HOME ENERGY REPORTING - WY 2016	OTHER	94	0	0	0	0	0	0	0	94
1823920	DSR COSTS AMORTIZED	104045	HOME ENERGY EFF INCENT PROG Y-2016 CAT1	OTHER	659	0	0	0	0	0	0	0	659

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823920	DSR COSTS AMORTIZED	104046	LOW-INCOME WEATHERZTN - WY 2016 CAT1	OTHER	14	0	0	0	0	0	0	0	14
1823920	DSR COSTS AMORTIZED	104047	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	79	0	0	0	0	0	0	0	79
1823920	DSR COSTS AMORTIZED	104048	PORTFOLIO WY-2016 CAT1	OTHER	131	0	0	0	0	0	0	0	131
1823920	DSR COSTS AMORTIZED	104049	PORTFOLIO WY-2016 CAT2	OTHER	37	0	0	0	0	0	0	0	37
1823920	DSR COSTS AMORTIZED	104050	PORTFOLIO WY-2016 CAT3	OTHER	45	0	0	0	0	0	0	0	45
1823920	DSR COSTS AMORTIZED	104051	REFRIGERATOR RECYCLING-WY -2016 CAT1	OTHER	16	0	0	0	0	0	0	0	16
1823920	DSR COSTS AMORTIZED	104052	REFRIG RECYCLE COMM -WY 2016 CAT2	OTHER	1	0	0	0	0	0	0	0	1
1823920	DSR COSTS AMORTIZED	104053	REFRIG RECYCLE COMM -WY 2016 CAT3	OTHER	-1	0	0	0	0	0	0	0	-1
1823920	DSR COSTS AMORTIZED	104054	WSB- Wattsmart Bus Comm- WY Cat2 -2016	OTHER	1,449	0	0	0	0	0	0	0	1,449
1823920	DSR COSTS AMORTIZED	104055	WBS- Wattsmart Business Ind -WY Cat2-201	OTHER	193	0	0	0	0	0	0	0	193
1823920	DSR COSTS AMORTIZED	104056	WSB - Wattsmart Business - WY Cat 2- 201	OTHER	912	0	0	0	0	0	0	0	912
1823920	DSR COSTS AMORTIZED	104057	WSB Wattsmart Business Comm- WY Cat3 -20	OTHER	467	0	0	0	0	0	0	0	467
1823920	DSR COSTS AMORTIZED	104058	WBS- Wattsmart Bus Ind- WY Cat3-2016	OTHER	1,239	0	0	0	0	0	0	0	1,239
1823920	DSR COSTS AMORTIZED	104059	WSB- Wattsmart Business Agric- WY Cat2 -	OTHER	4	0	0	0	0	0	0	0	4
1823920	DSR COSTS AMORTIZED	104060	WSB- Wattsmart Business Agric- WY Cat3 -	OTHER	2	0	0	0	0	0	0	0	2
1823920	DSR COSTS AMORTIZED	104061	WSB- Wattsmart Business- WY Cat 3- 2016	OTHER	602	0	0	0	0	0	0	0	602
1823920	DSR COSTS AMORTIZED	104080	OUTREACH & COMM WATTSMT WY-2016 CAT2	OTHER	44	0	0	0	0	0	0	0	44
1823920	DSR COSTS AMORTIZED	104081	OUTREACH & COMM WATTSMT WY-2016 CAT3	OTHER	42	0	0	0	0	0	0	0	42
1823920	DSR COSTS AMORTIZED	104109	WA DSM - 186055 Clear Acct Balance	OTHER	-841	0	0	0	0	0	0	0	-841
1823920	DSR COSTS AMORTIZED	104110	ID DSM - 186025 Clear Acct Balance	OTHER	398	0	0	0	0	0	0	0	398
1823920	DSR COSTS AMORTIZED	104111	WY DSM - 186065 Clear Acct Balance	OTHER	-1,405	0	0	0	0	0	0	0	-1,405
1823920 Total					**94,827**	**0**	**0**	**0**	**0**	**0**	**68**	**0**	**94,759**
1823930	DSR COSTS NOT AMORT	102573	ENERGY FINANSWER ID/UT 2006	IDU	0	0	0	0	0	0	0	0	0
1823930	DSR COSTS NOT AMORT	102574	INDUSTRIAL FINANSWER-ID-UT 2006	IDU	3	0	0	0	0	0	3	0	0
1823930	DSR COSTS NOT AMORT	102575	LOW INCOME WZ -ID-UT 2006	IDU	144	0	0	0	0	0	144	0	0
1823930	DSR COSTS NOT AMORT	102576	NEEA-IDAHO-UTAH 2006	IDU	359	0	0	0	0	0	359	0	0
1823930	DSR COSTS NOT AMORT	102577	IRRIGATION INTERRUPTIBLE ID-UT 2006	IDU	361	0	0	0	0	0	361	0	0
1823930	DSR COSTS NOT AMORT	102578	WEATHERIZATION LOANS-RESDL/ID-UT 2006	IDU	2	0	0	0	0	0	2	0	0
1823930	DSR COSTS NOT AMORT	102579	REFRIGERATOR RECYCLING PGM-ID-UT 2006	IDU	143	0	0	0	0	0	143	0	0
1823930	DSR COSTS NOT AMORT	102580	COMMERCIAL FINANSWER EXPR-ID-UT 2006	IDU	117	0	0	0	0	0	117	0	0
1823930	DSR COSTS NOT AMORT	102581	INDUSTRIAL FINANSWER EXPR-ID-UT 2006	IDU	47	0	0	0	0	0	47	0	0
1823930	DSR COSTS NOT AMORT	102582	IRRIGATION EFFICIENCY PRGRM-ID-UT 2006	IDU	246	0	0	0	0	0	246	0	0
1823930	DSR COSTS NOT AMORT	102758	HOME ENERGY EFFICIENCY INCENTIVE PROGM-I	IDU	103	0	0	0	0	0	103	0	0
1823930	DSR COSTS NOT AMORT	102808	WEATHERIZATION LOANS RESIDTL/ ID-UT 2007	OTHER	0	0	0	0	0	0	0	0	0
1823930	DSR COSTS NOT AMORT	102809	ENERGY FINANSWER IDU 2007	OTHER	4	0	0	0	0	0	0	0	4
1823930	DSR COSTS NOT AMORT	102810	Industrial Finanswer ID - 2007	OTHER	0	0	0	0	0	0	0	0	0
1823930	DSR COSTS NOT AMORT	102811	IRRIGATION INTERRUPTIBLE ID-UT 2007	OTHER	846	0	0	0	0	0	0	0	846
1823930	DSR COSTS NOT AMORT	102812	LOW INCOME WZ - ID-UT 2007	OTHER	101	0	0	0	0	0	0	0	101
1823930	DSR COSTS NOT AMORT	102813	NEEA - IDAHO - UTAH 2007	OTHER	361	0	0	0	0	0	0	0	361
1823930	DSR COSTS NOT AMORT	102814	REFRIGERATOR RECYCLING PGM - ID-UT 2007	OTHER	123	0	0	0	0	0	0	0	123
1823930	DSR COSTS NOT AMORT	102815	COMMERCIAL FINANSWER EXPR - ID-UT 2007	OTHER	61	0	0	0	0	0	0	0	61

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1823930	DSR COSTS NOT AMORT	102816	INDUSTRIAL FINANSWER EXPR - ID-UT 2007	OTHER	120	0	0	0	0	0	0	0	120
1823930	DSR COSTS NOT AMORT	102817	IRRIGATION EFFICIENCY PRGRM - ID-UT 2007	OTHER	275	0	0	0	0	0	0	0	275
1823930	DSR COSTS NOT AMORT	102818	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	229	0	0	0	0	0	0	0	229
1823930	DSR COSTS NOT AMORT	102896	ENERGY FINANSWER - ID/UT 2008	OTHER	19	0	0	0	0	0	0	0	19
1823930	DSR COSTS NOT AMORT	102897	INDUSTRIAL FINANSWER - ID-UT 2008	OTHER	102	0	0	0	0	0	0	0	102
1823930	DSR COSTS NOT AMORT	102898	IRRIGATION INTERRUPTIBLE - IDAHO - 2008	OTHER	3,127	0	0	0	0	0	0	0	3,127
1823930	DSR COSTS NOT AMORT	102899	LOW INCOME WEATHERIZATION - IDAHO 2008	OTHER	165	0	0	0	0	0	0	0	165
1823930	DSR COSTS NOT AMORT	102900	NEEA - IDAHO - 2008	OTHER	317	0	0	0	0	0	0	0	317
1823930	DSR COSTS NOT AMORT	102901	REFRIGERATOR RECYCLING PRGM - IDAHO 2008	OTHER	113	0	0	0	0	0	0	0	113
1823930	DSR COSTS NOT AMORT	102902	COMMERCIAL FINANSWER EXPRESS - IDAHO 200	OTHER	108	0	0	0	0	0	0	0	108
1823930	DSR COSTS NOT AMORT	102903	INDUSTRIAL FINANSWER - IDAHO - 2008	OTHER	58	0	0	0	0	0	0	0	58
1823930	DSR COSTS NOT AMORT	102904	IRRIGATION EFFICIENCY PRGM - IDAHO - 200	OTHER	268	0	0	0	0	0	0	0	268
1823930	DSR COSTS NOT AMORT	102905	HOME ENERGY EFF INCENTIVE PROGRAM - IDAH	OTHER	490	0	0	0	0	0	0	0	490
1823930	DSR COSTS NOT AMORT	102957	CATEGORY 1 - WYOMING - 2008	OTHER	17	0	0	0	0	0	0	0	17
1823930	DSR COSTS NOT AMORT	102958	CATEGORY 2 - WYOMING - 2008	OTHER	9	0	0	0	0	0	0	0	9
1823930	DSR COSTS NOT AMORT	102959	CATEGORY 3 - WYOMING - 2008	OTHER	33	0	0	0	0	0	0	0	33
1823930	DSR COSTS NOT AMORT	102966	ENERGY FINANSWER - ID/UT 2009	OTHER	50	0	0	0	0	0	0	0	50
1823930	DSR COSTS NOT AMORT	102967	INDUSTRIAL FINANSWER - ID-UT 2009	OTHER	309	0	0	0	0	0	0	0	309
1823930	DSR COSTS NOT AMORT	102968	IRRIGATION INTERRUPTIBLE ID-UT 2009	OTHER	3,816	0	0	0	0	0	0	0	3,816
1823930	DSR COSTS NOT AMORT	102969	LOW INCOME WZ - ID-UT 2009	OTHER	198	0	0	0	0	0	0	0	198
1823930	DSR COSTS NOT AMORT	102970	NEEA - IDAHO - UTAH 2009	OTHER	287	0	0	0	0	0	0	0	287
1823930	DSR COSTS NOT AMORT	102971	REFRIGERATOR RECYCLING PGM - ID-UT 2009	OTHER	108	0	0	0	0	0	0	0	108
1823930	DSR COSTS NOT AMORT	102972	COMMERCIAL FINANSWER EXPR - ID-UT 2009	OTHER	190	0	0	0	0	0	0	0	190
1823930	DSR COSTS NOT AMORT	102973	INDUSTRIAL FINANSWER EXPR - ID-UT 2009	OTHER	74	0	0	0	0	0	0	0	74
1823930	DSR COSTS NOT AMORT	102974	IRRIGATION EFFICIENCY PRGRM - ID-UT 2009	OTHER	807	0	0	0	0	0	0	0	807
1823930	DSR COSTS NOT AMORT	102975	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	594	0	0	0	0	0	0	0	594
1823930	DSR COSTS NOT AMORT	103061	ENERGY FINANSWER - ID/UT 2010	OTHER	47	0	0	0	0	0	0	0	47
1823930	DSR COSTS NOT AMORT	103062	INDUSTRIAL FINANSWER - ID-UT 2010	OTHER	322	0	0	0	0	0	0	0	322
1823930	DSR COSTS NOT AMORT	103063	IRRIGATION INTERRUPTIBLE ID-UT 2010	OTHER	4,283	0	0	0	0	0	0	0	4,283
1823930	DSR COSTS NOT AMORT	103064	LOW INCOME WZ - ID-UT 2010	OTHER	134	0	0	0	0	0	0	0	134
1823930	DSR COSTS NOT AMORT	103065	NEEA - IDAHO - UTAH 2010	OTHER	0	0	0	0	0	0	0	0	0
1823930	DSR COSTS NOT AMORT	103066	REFRIGERATOR RECYCLING PGM - ID-UT 2010	OTHER	166	0	0	0	0	0	0	0	166
1823930	DSR COSTS NOT AMORT	103067	COMMERCIAL FINANSWER EXPR - ID-UT 2010	OTHER	513	0	0	0	0	0	0	0	513
1823930	DSR COSTS NOT AMORT	103068	INDUSTRIAL FINANSWER EXPR - ID-UT 2010	OTHER	107	0	0	0	0	0	0	0	107
1823930	DSR COSTS NOT AMORT	103069	IRRIGATION EFFICIENCY PRGRM - ID-UT 2010	OTHER	637	0	0	0	0	0	0	0	637
1823930	DSR COSTS NOT AMORT	103070	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	1,305	0	0	0	0	0	0	0	1,305
1823930	DSR COSTS NOT AMORT	103171	ENERGY FINANSWER - ID/UT 2011	OTHER	23	0	0	0	0	0	0	0	23
1823930	DSR COSTS NOT AMORT	103172	INDUSTRIAL FINANSWER - ID-UT 2011	OTHER	143	0	0	0	0	0	0	0	143
1823930	DSR COSTS NOT AMORT	103173	IRRIGATION INTERRUPTIBLE ID-UT 2011	OTHER	37	0	0	0	0	0	0	0	37
1823930	DSR COSTS NOT AMORT	103174	LOW INCOME WZ - ID-UT 2011	OTHER	425	0	0	0	0	0	0	0	425
1823930	DSR COSTS NOT AMORT	103176	REFRIGERATOR RECYCLING PGM - ID-UT 2011	OTHER	126	0	0	0	0	0	0	0	126

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1823930	DSR COSTS NOT AMORT	103177	COMMERCIAL FINANSWER EXPR - ID-UT 2011	OTHER	632	0	0	0	0	0	0	0	632
1823930	DSR COSTS NOT AMORT	103178	INDUSTRIAL FINANSWER EXPR - ID-UT 2011	OTHER	77	0	0	0	0	0	0	0	77
1823930	DSR COSTS NOT AMORT	103179	IRRIGATION EFFICIENCY PRGRM - ID-UT 2011	OTHER	508	0	0	0	0	0	0	0	508
1823930	DSR COSTS NOT AMORT	103180	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	699	0	0	0	0	0	0	0	699
1823930	DSR COSTS NOT AMORT	103312	ENERGY FINANSWER - ID 2012	OTHER	35	0	0	0	0	0	0	0	35
1823930	DSR COSTS NOT AMORT	103313	INDUSTRIAL FINANSWER - ID 2012	OTHER	303	0	0	0	0	0	0	0	303
1823930	DSR COSTS NOT AMORT	103314	IRRIGATION INTERRUPTIBLE- ID 2012	OTHER	44	0	0	0	0	0	0	0	44
1823930	DSR COSTS NOT AMORT	103315	LOW INCOME WZ - ID- 2012	OTHER	296	0	0	0	0	0	0	0	296
1823930	DSR COSTS NOT AMORT	103317	REFRIGERATOR RECYCLING PGM - ID 2012	OTHER	115	0	0	0	0	0	0	0	115
1823930	DSR COSTS NOT AMORT	103318	COMMERCIAL FINANSWER EXPR - ID 2012	OTHER	706	0	0	0	0	0	0	0	706
1823930	DSR COSTS NOT AMORT	103319	INDUSTRIAL FINANSWER EXPR - ID 2012	OTHER	226	0	0	0	0	0	0	0	226
1823930	DSR COSTS NOT AMORT	103320	IRRIGATION EFFICIENCY PRGRM - ID 2012	OTHER	847	0	0	0	0	0	0	0	847
1823930	DSR COSTS NOT AMORT	103321	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	789	0	0	0	0	0	0	0	789
1823930	DSR COSTS NOT AMORT	103322	COMMERCIAL DIRECT INSTALL - ID 2012	OTHER	0	0	0	0	0	0	0	0	0
1823930	DSR COSTS NOT AMORT	103323	AGRICULURAL FINANSWER EXPR - ID 2012	OTHER	7	0	0	0	0	0	0	0	7
1823930	DSR COSTS NOT AMORT	103398	RECOMMISSIONING INDUSTRIAL - UT 2012	OTHER	6	0	0	0	0	0	0	0	6
1823930	DSR COSTS NOT AMORT	103634	AGRICULURAL FINANSWER EXPR - ID 2013	OTHER	21	0	0	0	0	0	0	0	21
1823930	DSR COSTS NOT AMORT	103635	ENERGY FINANSWER - ID 2013	OTHER	77	0	0	0	0	0	0	0	77
1823930	DSR COSTS NOT AMORT	103636	INDUSTRIAL FINANSWER - ID 2013	OTHER	294	0	0	0	0	0	0	0	294
1823930	DSR COSTS NOT AMORT	103638	LOW INCOME WZ - ID- 2013	OTHER	226	0	0	0	0	0	0	0	226
1823930	DSR COSTS NOT AMORT	103640	REFRIGERATOR RECYCLING PGM - ID 2013	OTHER	115	0	0	0	0	0	0	0	115
1823930	DSR COSTS NOT AMORT	103641	COMMERCIAL FINANSWER EXPR - ID 2013	OTHER	615	0	0	0	0	0	0	0	615
1823930	DSR COSTS NOT AMORT	103642	INDUSTRIAL FINANSWER EXPR - ID 2013	OTHER	363	0	0	0	0	0	0	0	363
1823930	DSR COSTS NOT AMORT	103643	IRRIGATION EFFICIENCY PRGRM - ID 2013	OTHER	1,222	0	0	0	0	0	0	0	1,222
1823930	DSR COSTS NOT AMORT	103644	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	844	0	0	0	0	0	0	0	844
1823930	DSR COSTS NOT AMORT	103672	RECOMMISSIONING INDUSTRIAL - UT 2013	OTHER	58	0	0	0	0	0	0	0	58
1823930	DSR COSTS NOT AMORT	103746	AGRICULURAL FINANSWER EXPR - ID 2014	OTHER	122	0	0	0	0	0	0	0	122
1823930	DSR COSTS NOT AMORT	103747	COMMERCIAL FINANSWER EXPR - ID 2014	OTHER	683	0	0	0	0	0	0	0	683
1823930	DSR COSTS NOT AMORT	103748	ENERGY FINANSWER - ID 2014	OTHER	154	0	0	0	0	0	0	0	154
1823930	DSR COSTS NOT AMORT	103749	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	854	0	0	0	0	0	0	0	854
1823930	DSR COSTS NOT AMORT	103750	INDUSTRIAL FINANSWER - ID 2014	OTHER	105	0	0	0	0	0	0	0	105
1823930	DSR COSTS NOT AMORT	103751	INDUSTRIAL FINANSWER EXPR - ID 2014	OTHER	268	0	0	0	0	0	0	0	268
1823930	DSR COSTS NOT AMORT	103752	IRRIGATION EFFICIENCY PRGRM - ID 2014	OTHER	449	0	0	0	0	0	0	0	449
1823930	DSR COSTS NOT AMORT	103753	LOW INCOME WZ - ID- 2014	OTHER	298	0	0	0	0	0	0	0	298
1823930	DSR COSTS NOT AMORT	103755	REFRIGERATOR RECYCLING PGM - ID 2014	OTHER	122	0	0	0	0	0	0	0	122
1823930	DSR COSTS NOT AMORT	103866	AGRICULURAL FINANSWER EXPR - ID 2015	OTHER	2	0	0	0	0	0	0	0	2
1823930	DSR COSTS NOT AMORT	103867	COMMERCIAL FINANSWER EXPR - ID 2015	OTHER	157	0	0	0	0	0	0	0	157
1823930	DSR COSTS NOT AMORT	103868	ENERGY FINANSWER - ID 2015	OTHER	6	0	0	0	0	0	0	0	6
1823930	DSR COSTS NOT AMORT	103869	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	848	0	0	0	0	0	0	0	848
1823930	DSR COSTS NOT AMORT	103870	INDUSTRIAL FINANSWER - ID 2015	OTHER	63	0	0	0	0	0	0	0	63
1823930	DSR COSTS NOT AMORT	103871	INDUSTRIAL FINANSWER EXPR - ID 2015	OTHER	80	0	0	0	0	0	0	0	80

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1823930	DSR COSTS NOT AMORT	103872	IRRIGATION EFFICIENCY PRGRM - ID 2015	OTHER	236	0	0	0	0	0	0	0	236
1823930	DSR COSTS NOT AMORT	103873	LOW INCOME WZ - ID- 2015	OTHER	296	0	0	0	0	0	0	0	296
1823930	DSR COSTS NOT AMORT	103875	REFRIGERATOR RECYCLING PGM - ID 2015	OTHER	106	0	0	0	0	0	0	0	106
1823930	DSR COSTS NOT AMORT	104014	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	450	0	0	0	0	0	0	0	450
1823930	DSR COSTS NOT AMORT	104016	IRRIGATION EFFICIENCY PRGRM - ID 2016	OTHER	80	0	0	0	0	0	0	0	80
1823930	DSR COSTS NOT AMORT	104017	LOW INCOME WZ - ID- 2016	OTHER	245	0	0	0	0	0	0	0	245
1823930	DSR COSTS NOT AMORT	104022	REFRIGERATOR RECYCLING PGM - ID 2016	OTHER	14	0	0	0	0	0	0	0	14
1823930 Total					**37,937**	**0**	**0**	**0**	**0**	**0**	**1,524**	**0**	**36,413**
1823940	DSR CARRYING CHARGES	102146	UT CARRYING CHARGE - 2001/2002	OTHER	3,457	0	0	0	0	0	0	0	3,457
1823940	DSR CARRYING CHARGES	102188	WA REVENUE RECOVERY - CARRYING CHG PENAL	OTHER	-680	0	0	0	0	0	0	0	-680
1823940	DSR CARRYING CHARGES	102766	DSR CARRYING CHARGES	IDU	163	0	0	0	0	0	163	0	0
1823940	DSR CARRYING CHARGES	103140	Wy DSM - Cat1 - Carrying Charges	OTHER	-102	0	0	0	0	0	0	0	-102
1823940	DSR CARRYING CHARGES	103141	Wy DSM - Cat2 - Carrying Charges	OTHER	-34	0	0	0	0	0	0	0	-34
1823940	DSR CARRYING CHARGES	103142	Wy DSM - Cat3 - Carrying Charges	OTHER	-86	0	0	0	0	0	0	0	-86
1823940 Total					**2,719**	**0**	**0**	**0**	**0**	**0**	**163**	**0**	**2,556**
1823990	OTHR REG ASSET-N CST	138020	Reg Asset Current - DSM	OTHER	12,651	0	0	0	0	0	0	0	12,651
1823990	OTHR REG ASSET-N CST	138050	Reg Asset Current - Def Net Power Costs	OTHER	35,192	0	0	0	0	0	0	0	35,192
1823990	OTHR REG ASSET-N CST	138055	Reg Asset Current - Def RECs in Rates	OTHER	1,373	0	0	0	0	0	0	0	1,373
1823990	OTHR REG ASSET-N CST	138060	Reg Asset Current - BPA Balancing Accts	OTHER	7,812	0	0	0	0	0	0	0	7,812
1823990	OTHR REG ASSET-N CST	138090	Reg Asset Current - Solar Feed-In	OTHER	3,507	0	0	0	0	0	0	0	3,507
1823990	OTHR REG ASSET-N CST	138190	Reg Asset Current - Other	OTHER	2,436	0	0	0	0	0	0	0	2,436
1823990	OTHR REG ASSET-N CST	186100	Calif Alternative Rate for Energy (CARE)	OTHER	396	0	0	0	0	0	0	0	396
1823990	OTHR REG ASSET-N CST	186119	Reg Asset - DSM - CA - Balance Reclass	OTHER	2,453	0	0	0	0	0	0	0	2,453
1823990	OTHR REG ASSET-N CST	186129	Reg Asset - DSM - ID - Balance Reclass	OTHER	880	0	0	0	0	0	0	0	880
1823990	OTHR REG ASSET-N CST	186137	RegA - DSM - OR - Reclass to Current	OTHER	-191	0	0	0	0	0	0	0	-191
1823990	OTHR REG ASSET-N CST	186147	RegA - DSM - UT - Reclass to Current	OTHER	-12,459	0	0	0	0	0	0	0	-12,459
1823990	OTHR REG ASSET-N CST	186149	Reg Asset - DSM - UT - Balance Reclass	OTHER	9,181	0	0	0	0	0	0	0	9,181
1823990	OTHR REG ASSET-N CST	186159	Reg Asset - DSM - WA - Balance Reclass	OTHER	3,933	0	0	0	0	0	0	0	3,933
1823990	OTHR REG ASSET-N CST	186169	Reg Asset - DSM - WY - Balance Reclass	OTHER	406	0	0	0	0	0	0	0	406
1823990	OTHR REG ASSET-N CST	186502	POWERDALE HYDRO DECOM REG ASSET - ID	IDU	40	0	0	0	0	0	40	0	0
1823990	OTHR REG ASSET-N CST	187042	Reg Asset - CA GHG Allowances	OTHER	-1,686	0	0	0	0	0	0	0	-1,686
1823990	OTHR REG ASSET-N CST	187049	RegA - CA GHG Allowances - Balance Recl	OTHER	1,686	0	0	0	0	0	0	0	1,686
1823990	OTHR REG ASSET-N CST	187051	WASHINGTON COLSTRIP #3 REGULATORY ASSET	WA	83	0	0	83	0	0	0	0	0
1823990	OTHR REG ASSET-N CST	187191	Reg Asset - WA RPS Purchase	OTHER	41	0	0	0	0	0	0	0	41
1823990	OTHR REG ASSET-N CST	187255	RegA - BPA Balancing Accts - Recl to Cur	OTHER	-7,812	0	0	0	0	0	0	0	-7,812
1823990	OTHR REG ASSET-N CST	187300	CA - Jan 2010 Storm Costs	OTHER	1,445	0	0	0	0	0	0	0	1,445
1823990	OTHR REG ASSET-N CST	187305	RegA - ID 2017 Protocol - MSP Deferral	IDU	225	0	0	0	0	0	225	0	0
1823990	OTHR REG ASSET-N CST	187306	RegA - UT 2017 Protocol - MSP Deferral	UT	11,000	0	0	0	0	11,000	0	0	0
1823990	OTHR REG ASSET-N CST	187307	RegA - WY 2017 Protocol - MSP Deferral	WYU	3,200	0	0	0	3,200	0	0	0	0
1823990	OTHR REG ASSET-N CST	187311	Contra Reg Asset-Carbon Plt Dec/Inv-CA	CA	-52	-52	0	0	0	0	0	0	0
1823990	OTHR REG ASSET-N CST	187320	Reg Asset - Deprec Increase - ID	IDU	35	0	0	0	0	0	35	0	0

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Regulatory Assets
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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823990	OTHR REG ASSET-N CST	187321	Reg Asset - Deprec Increase - UT	UT	1,537	0	0	0	0	1,537	0	0	0
1823990	OTHR REG ASSET-N CST	187322	Reg Asset - Deprec Increase - WY	WYP	5,306	0	0	0	5,306	0	0	0	0
1823990	OTHR REG ASSET-N CST	187330	Reg Asset - Carbon Unrec Plant - ID	IDU	718	0	0	0	0	0	718	0	0
1823990	OTHR REG ASSET-N CST	187332	Reg Asset - Carbon Unrec Plant - UT	UT	5,167	0	0	0	0	5,167	0	0	0
1823990	OTHR REG ASSET-N CST	187334	Reg Asset - Carbon Unrec Plant - WY	WYP	1,737	0	0	0	1,737	0	0	0	0
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	SG	3,449	53	897	272	504	1,517	203	1	0
1823990	OTHR REG ASSET-N CST	187345	Reg Asset - UT - Pref Stock Redemp Loss	OTHER	389	0	0	0	0	0	0	0	389
1823990	OTHR REG ASSET-N CST	187346	Reg Asset - WY - Pref Stock Redemp Loss	OTHER	134	0	0	0	0	0	0	0	134
1823990	OTHR REG ASSET-N CST	187347	Reg Asset - WA - Pref Stock Redemp Loss	OTHER	62	0	0	0	0	0	0	0	62
1823990	OTHR REG ASSET-N CST	187350	ID - Deferred Overburden Costs	OTHER	458	0	0	0	0	0	0	0	458
1823990	OTHR REG ASSET-N CST	187351	WY - Deferred Overburden Costs	WYP	1,290	0	0	0	1,290	0	0	0	0
1823990	OTHR REG ASSET-N CST	187356	Reg Asset-WA-Merwin Project	OTHER	-3	0	0	0	0	0	0	0	-3
1823990	OTHR REG ASSET-N CST	187357	CA Mobile Home Park Conversion (MHPCBA)	OTHER	201	0	0	0	0	0	0	0	201
1823990	OTHR REG ASSET-N CST	187371	REG ASSET - CA SOLAR FEED-IN TARIFF	OTHER	-623	0	0	0	0	0	0	0	-623
1823990	OTHR REG ASSET-N CST	187378	Reg Asset-OR Solar Feed-In Tariff 2018	OTHER	1,884	0	0	0	0	0	0	0	1,884
1823990	OTHR REG ASSET-N CST	187379	Reg Asset-OR Solar Feed-In Tariff 2019	OTHER	3,051	0	0	0	0	0	0	0	3,051
1823990	OTHR REG ASSET-N CST	187380	Reg Asset - UT Solar Incentive Program	OTHER	-7,992	0	0	0	0	0	0	0	-7,992
1823990	OTHR REG ASSET-N CST	187383	RegA - OR Solar Feed-In - Recl to Curr	OTHER	-3,409	0	0	0	0	0	0	0	-3,409
1823990	OTHR REG ASSET-N CST	187384	RegA - UT Solar Feed-In - Recl to Curr	OTHER	-98	0	0	0	0	0	0	0	-98
1823990	OTHR REG ASSET-N CST	187387	Reg Asset-Utah STEP Pilot Prog Bal Acct	OTHER	-16,006	0	0	0	0	0	0	0	-16,006
1823990	OTHR REG ASSET-N CST	187390	UT-Klamath Hydro Relicensing Costs	OTHER	13,855	0	0	0	0	0	0	0	13,855
1823990	OTHR REG ASSET-N CST	187391	RegA - CA Solar Feed-In - Recl to Liab	OTHER	623	0	0	0	0	0	0	0	623
1823990	OTHR REG ASSET-N CST	187394	RegA - UT Solar Feed-In - Recl to Liab	OTHER	23,998	0	0	0	0	0	0	0	23,998
1823990	OTHR REG ASSET-N CST	187415	Reg Asset-UT Subscriber Solar Program	OTHER	1,711	0	0	0	0	0	0	0	1,711
1823990	OTHR REG ASSET-N CST	187420	RegA - OR Community Solar	OTHER	160	0	0	0	0	0	0	0	160
1823990	OTHR REG ASSET-N CST	187471	Reg A-WA Decoupling Mech Jul17-Jun18	OTHER	-1,755	0	0	0	0	0	0	0	-1,755
1823990	OTHR REG ASSET-N CST	187472	Reg A-WA Decoupling Mech Jul18-Jun19	OTHER	-456	0	0	0	0	0	0	0	-456
1823990	OTHR REG ASSET-N CST	187489	Reg A-WA Decoupling Mechanism-Reclass	OTHER	2,211	0	0	0	0	0	0	0	2,211
1823990	OTHR REG ASSET-N CST	187495	RegA - Other - Recl to Curr	OTHER	-2,436	0	0	0	0	0	0	0	-2,436
1823990	OTHR REG ASSET-N CST	187630	Reg Asset - UT EIM Expense Deferral	OTHER	8,657	0	0	0	0	0	0	0	8,657
1823990	OTHR REG ASSET-N CST	187631	Contra Reg Asset - UT EIM Deferral	OTHER	-8,657	0	0	0	0	0	0	0	-8,657
1823990	OTHR REG ASSET-N CST	187660	RegA-OR Transp Electrification Pilot	OTHER	390	0	0	0	0	0	0	0	390
1823990	OTHR REG ASSET-N CST	187662	RegA-CA Transp Electrification Pilot	OTHER	-445	0	0	0	0	0	0	0	-445
1823990	OTHR REG ASSET-N CST	187664	RegA-WA Transp Electrification Pilot	OTHER	39	0	0	0	0	0	0	0	39
1823990	OTHR REG ASSET-N CST	187839	Reg Asset - UT RBA CY2018	OTHER	827	0	0	0	0	0	0	0	827
1823990	OTHR REG ASSET-N CST	187856	Reg Asset - WY ECAM CY2016	OTHER	-57	0	0	0	0	0	0	0	-57
1823990	OTHR REG ASSET-N CST	187857	Reg Asset - WY ECAM CY2017	OTHER	131	0	0	0	0	0	0	0	131
1823990	OTHR REG ASSET-N CST	187858	Reg Asset - WY ECAM CY2018	OTHER	6,340	0	0	0	0	0	0	0	6,340
1823990	OTHR REG ASSET-N CST	187859	Reg Asset - WY ECAM CY2019	OTHER	461	0	0	0	0	0	0	0	461
1823990	OTHR REG ASSET-N CST	187867	Reg Asset - WY RRA CY2017	OTHER	21	0	0	0	0	0	0	0	21
1823990	OTHR REG ASSET-N CST	187868	Reg Asset - WY RRA CY2018	OTHER	499	0	0	0	0	0	0	0	499

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Regulatory Assets
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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823990	OTHR REG ASSET-N CST	187869	Reg Asset - WY RRA CY2019	OTHER	-86	0	0	0	0	0	0	0	-86
1823990	OTHR REG ASSET-N CST	187877	Contra Reg Asset - WY ECAM CY2018	OTHER	-674	0	0	0	0	0	0	0	-674
1823990	OTHR REG ASSET-N CST	187879	Contra Reg Asset - WY ECAM CY2019	OTHER	-84	0	0	0	0	0	0	0	-84
1823990	OTHR REG ASSET-N CST	187880	Reg Asset - UT RBA CY2019	OTHER	-330	0	0	0	0	0	0	0	-330
1823990	OTHR REG ASSET-N CST	187886	Reg Asset-OR RPS Compliance Purchases	OTHER	13	0	0	0	0	0	0	0	13
1823990	OTHR REG ASSET-N CST	187888	RegA - WA RECs in Rates - Recl to Curr	OTHER	-41	0	0	0	0	0	0	0	-41
1823990	OTHR REG ASSET-N CST	187894	RegA - OR RECs in Rates - Recl to Curr	OTHER	-13	0	0	0	0	0	0	0	-13
1823990	OTHR REG ASSET-N CST	187896	RegA - UT RECs in Rates - Recl to Curr	OTHER	-800	0	0	0	0	0	0	0	-800
1823990	OTHR REG ASSET-N CST	187897	RegA - UT RECs in Rates - Recl to Liab	OTHER	303	0	0	0	0	0	0	0	303
1823990	OTHR REG ASSET-N CST	187898	RegA - Def RECs in Rates - Recl to Curr	OTHER	-519	0	0	0	0	0	0	0	-519
1823990	OTHR REG ASSET-N CST	187899	RegA - WY RECs in Rates - Recl to Liab	OTHER	86	0	0	0	0	0	0	0	86
1823990	OTHR REG ASSET-N CST	187911	REG ASSET - LAKE SIDE LIQ. DAMAGES - WY	WYP	772	0	0	0	772	0	0	0	0
1823990	OTHR REG ASSET-N CST	187913	Reg Asset - Goodnoe Hills Liq. Damages -	WYP	308	0	0	0	308	0	0	0	0
1823990	OTHR REG ASSET-N CST	187914	"Reg Asset-UT-Liq. Damages JB4, N1&2"	UT	507	0	0	0	0	507	0	0	0
1823990	OTHR REG ASSET-N CST	187915	Reg Asset-WY-Liq. Damages N2	WYP	83	0	0	0	83	0	0	0	0
1823990	OTHR REG ASSET-N CST	187952	DEFERRED INTERVENER	OTHER	0	0	0	0	0	0	0	0	0
1823990	OTHR REG ASSET-N CST	187956	CA DEFERRED INTERVENOR FUNDING	OTHER	43	0	0	0	0	0	0	0	43
1823990	OTHR REG ASSET-N CST	187958	ID Deferred Intervenor Funding	IDU	67	0	0	0	0	0	67	0	0
1823990	OTHR REG ASSET-N CST	187964	RegA - Intervenor Fees - Recl to Liab	OTHER	108	0	0	0	0	0	0	0	108
1823990	OTHR REG ASSET-N CST	187967	RegA - OR Asset Sale Gain-Balance Recl	OTHER	703	0	0	0	0	0	0	0	703
1823990	OTHR REG ASSET-N CST	187968	Reg A - Insurance Reserves - Reclass	OTHER	11,606	0	0	0	0	0	0	0	11,606
1823990	OTHR REG ASSET-N CST	187973	Contra Reg Asset - CA ECAC CY2015	OTHER	-337	0	0	0	0	0	0	0	-337
1823990	OTHR REG ASSET-N CST	187974	Contra Reg Asset - CA ECAC CY2016	OTHER	-171	0	0	0	0	0	0	0	-171
1823990	OTHR REG ASSET-N CST	187975	Reg Asset - CA ECAC	OTHER	1,401	0	0	0	0	0	0	0	1,401
1823990	OTHR REG ASSET-N CST	187977	Contra Reg Asset - CA ECAC CY2017	OTHER	-107	0	0	0	0	0	0	0	-107
1823990	OTHR REG ASSET-N CST	187978	Reg Asset - CA ECAC CY2018	OTHER	3,728	0	0	0	0	0	0	0	3,728
1823990	OTHR REG ASSET-N CST	187979	Contra Reg Asset - CA ECAC CY2018	OTHER	-218	0	0	0	0	0	0	0	-218
1823990	OTHR REG ASSET-N CST	189500	Reg Asset - CA ECAC CY2019	OTHER	1,168	0	0	0	0	0	0	0	1,168
1823990	OTHR REG ASSET-N CST	189501	Contra Reg Asset - CA ECAC CY2019	OTHER	-58	0	0	0	0	0	0	0	-58
1823990	OTHR REG ASSET-N CST	189502	Reg Asset - CA ECAC CY2020	OTHER	60	0	0	0	0	0	0	0	60
1823990	OTHR REG ASSET-N CST	189503	Contra Reg Asset - CA ECAC CY2020	OTHER	-3	0	0	0	0	0	0	0	-3
1823990	OTHR REG ASSET-N CST	189504	Reg Asset - CA ECAC CY2021	OTHER	45	0	0	0	0	0	0	0	45
1823990	OTHR REG ASSET-N CST	189505	Contra Reg Asset - CA ECAC CY2021	OTHER	-2	0	0	0	0	0	0	0	-2
1823990	OTHR REG ASSET-N CST	189528	RegA - CA Def Exc NPC - Recl to Curr	OTHER	-2,541	0	0	0	0	0	0	0	-2,541
1823990	OTHR REG ASSET-N CST	189533	Reg Asset - ID ECAM CY 2018	OTHER	13,622	0	0	0	0	0	0	0	13,622
1823990	OTHR REG ASSET-N CST	189534	Reg Asset-ID ECAM CY 2019	OTHER	10,116	0	0	0	0	0	0	0	10,116
1823990	OTHR REG ASSET-N CST	189535	Reg Asset-ID ECAM CY 2020	OTHER	380	0	0	0	0	0	0	0	380
1823990	OTHR REG ASSET-N CST	189536	Reg Asset-ID ECAM CY 2021	OTHER	280	0	0	0	0	0	0	0	280
1823990	OTHR REG ASSET-N CST	189544	Contra Reg Asset - ID ECAM CY 2019	OTHER	-387	0	0	0	0	0	0	0	-387
1823990	OTHR REG ASSET-N CST	189545	Contra Reg Asset - ID ECAM CY 2020	OTHER	-19	0	0	0	0	0	0	0	-19
1823990	OTHR REG ASSET-N CST	189546	Contra Reg Asset - ID ECAM CY 2021	OTHER	-14	0	0	0	0	0	0	0	-14

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Allocation Method - Factor 2020 Protocol
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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823990	OTHR REG ASSET-N CST	189568	RegA - ID Def Exc NPC - Recl to Curr	OTHER	-14,433	0	0	0	0	0	0	0	-14,433
1823990	OTHR REG ASSET-N CST	189570	Reg Asset - OR TAM CY2020	OTHER	1,461	0	0	0	0	0	0	0	1,461
1823990	OTHR REG ASSET-N CST	189571	Reg Asset - OR TAM CY2021	OTHER	1,599	0	0	0	0	0	0	0	1,599
1823990	OTHR REG ASSET-N CST	189580	Contra Reg Asset - OR TAM CY2020	OTHER	-73	0	0	0	0	0	0	0	-73
1823990	OTHR REG ASSET-N CST	189581	Contra Reg Asset - OR TAM CY2021	OTHER	-80	0	0	0	0	0	0	0	-80
1823990	OTHR REG ASSET-N CST	189608	Reg Asset - UT EBA CY2018	OTHER	20,652	0	0	0	0	0	0	0	20,652
1823990	OTHR REG ASSET-N CST	189609	Reg Asset - UT EBA CY2019	OTHER	14,431	0	0	0	0	0	0	0	14,431
1823990	OTHR REG ASSET-N CST	189610	Reg Asset - UT EBA CY2020	OTHER	2,656	0	0	0	0	0	0	0	2,656
1823990	OTHR REG ASSET-N CST	189611	Reg Asset - UT EBA CY2021	OTHER	1,959	0	0	0	0	0	0	0	1,959
1823990	OTHR REG ASSET-N CST	189618	Contra Reg Asset - UT EBA CY2018	OTHER	-1,934	0	0	0	0	0	0	0	-1,934
1823990	OTHR REG ASSET-N CST	189619	Contra Reg Asset - UT EBA CY2019	OTHER	-1,360	0	0	0	0	0	0	0	-1,360
1823990	OTHR REG ASSET-N CST	189620	Contra Reg Asset - UT EBA CY2020	OTHER	-133	0	0	0	0	0	0	0	-133
1823990	OTHR REG ASSET-N CST	189621	Contra Reg Asset - UT EBA CY2021	OTHER	-98	0	0	0	0	0	0	0	-98
1823990	OTHR REG ASSET-N CST	189638	RegA - UT Def Exc NPC - Recl to Curr	OTHER	-12,478	0	0	0	0	0	0	0	-12,478
1823990	OTHR REG ASSET-N CST	189650	Reg Asset - WY ECAM CY2020	OTHER	718	0	0	0	0	0	0	0	718
1823990	OTHR REG ASSET-N CST	189651	Reg Asset - WY ECAM CY2021	OTHER	530	0	0	0	0	0	0	0	530
1823990	OTHR REG ASSET-N CST	189660	Contra Reg Asset - WY ECAM CY2020	OTHER	-36	0	0	0	0	0	0	0	-36
1823990	OTHR REG ASSET-N CST	189661	Contra Reg Asset - WY ECAM CY2021	OTHER	-26	0	0	0	0	0	0	0	-26
1823990	OTHR REG ASSET-N CST	189688	RegA - WY Def Exc NPC - Recl to Curr	OTHER	-5,740	0	0	0	0	0	0	0	-5,740
1823990 Total					**165,753**	**1**	**897**	**355**	**13,201**	**19,728**	**1,288**	**1**	**130,282**
1823999	REGULATORY ASST-OTH	186011	DSM Reg Asset - Accruals - CA	OTHER	340	0	0	0	0	0	0	0	340
1823999	REGULATORY ASST-OTH	186015	DSM Reg Asset - Balancing Acct - CA	OTHER	-2,793	0	0	0	0	0	0	0	-2,793
1823999	REGULATORY ASST-OTH	186021	DSM Reg Asset - Accruals - ID	OTHER	516	0	0	0	0	0	0	0	516
1823999	REGULATORY ASST-OTH	186025	DSM Reg Asset - Balancing Acct - ID	OTHER	-1,396	0	0	0	0	0	0	0	-1,396
1823999	REGULATORY ASST-OTH	186035	DSM Reg Asset - Balancing Acct - OR	OTHER	191	0	0	0	0	0	0	0	191
1823999	REGULATORY ASST-OTH	186041	DSM Reg Asset - Accruals - UT	OTHER	4,724	0	0	0	0	0	0	0	4,724
1823999	REGULATORY ASST-OTH	186045	DSM Reg Asset - Balancing Acct - UT	OTHER	-122,859	0	0	0	0	0	0	0	-122,859
1823999	REGULATORY ASST-OTH	186051	DSM Reg Asset - Accruals - WA	OTHER	871	0	0	0	0	0	0	0	871
1823999	REGULATORY ASST-OTH	186055	DSM Reg Asset - Balancing Acct - WA	OTHER	-4,804	0	0	0	0	0	0	0	-4,804
1823999	REGULATORY ASST-OTH	186061	DSM Reg Asset - Accruals - WY	OTHER	388	0	0	0	0	0	0	0	388
1823999	REGULATORY ASST-OTH	186065	DSM Reg Asset - Balancing Acct - WY	OTHER	-1,780	0	0	0	0	0	0	0	-1,780
1823999	REGULATORY ASST-OTH	186071	DSM Reg Asset - Accruals - WY Cat 1	OTHER	305	0	0	0	0	0	0	0	305
1823999	REGULATORY ASST-OTH	186075	DSM Reg Asset-Balancing Acct-WY Cat 1	OTHER	-1,940	0	0	0	0	0	0	0	-1,940
1823999	REGULATORY ASST-OTH	186081	DSM Reg Asset - Accruals - WY Cat 2	OTHER	226	0	0	0	0	0	0	0	226
1823999	REGULATORY ASST-OTH	186085	DSM Reg Asset-Balancing Acct-WY Cat 2	OTHER	-80	0	0	0	0	0	0	0	-80
1823999 Total					**-128,089**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-128,089**
Grand Total					**758,495**	**11,923**	**164,348**	**42,482**	**97,227**	**296,577**	**39,391**	**158**	**106,390**

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Depreciation Reserve
Balances as of June 2019
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(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3102000	LAND RIGHTS	SG	-29,397	-452	-7,650	-2,320	-4,299	-12,934	-1,734	-8	0
1080000	AC PR DPR EL PL SR	3103000	WATER RIGHTS	SG	-14,473	-222	-3,766	-1,142	-2,117	-6,368	-854	-4	0
1080000	AC PR DPR EL PL SR	3110000	STRUCTURES AND IMPROVEMENTS	SG	-547,674	-8,416	-142,519	-43,223	-80,099	-240,963	-32,299	-155	0
1080000	AC PR DPR EL PL SR	3120000	BOILER PLANT EQUIPMENT	SG	-1,936,846	-29,764	-504,018	-152,857	-283,270	-852,164	-114,225	-549	0
1080000	AC PR DPR EL PL SR	3140000	TURBOGENERATOR UNITS	SG	-442,828	-6,805	-115,236	-34,948	-64,765	-194,833	-26,116	-125	0
1080000	AC PR DPR EL PL SR	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	-245,783	-3,777	-63,959	-19,397	-35,947	-108,139	-14,495	-70	0
1080000	AC PR DPR EL PL SR	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	-37	-1	-10	-3	-5	-16	-2	0	0
1080000	AC PR DPR EL PL SR	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	-17,602	-270	-4,580	-1,389	-2,574	-7,744	-1,038	-5	0
1080000	AC PR DPR EL PL SR	3302000	LAND RIGHTS	SG-P	-4,074	-63	-1,060	-322	-596	-1,793	-240	-1	0
1080000	AC PR DPR EL PL SR	3302000	LAND RIGHTS	SG-U	-59	-1	-15	-5	-9	-26	-3	0	0
1080000	AC PR DPR EL PL SR	3303000	WATER RIGHTS	SG-U	-113	-2	-30	-9	-17	-50	-7	0	0
1080000	AC PR DPR EL PL SR	3304000	FLOOD RIGHTS	SG-P	-249	-4	-65	-20	-36	-109	-15	0	0
1080000	AC PR DPR EL PL SR	3304000	FLOOD RIGHTS	SG-U	-71	-1	-18	-6	-10	-31	-4	0	0
1080000	AC PR DPR EL PL SR	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	-162	-2	-42	-13	-24	-71	-10	0	0
1080000	AC PR DPR EL PL SR	3310000	STRUCTURES AND IMPROVE	SG-P	-5	0	-1	0	-1	-2	0	0	0
1080000	AC PR DPR EL PL SR	3310000	STRUCTURES AND IMPROVE	SG-U	-5,155	-79	-1,341	-407	-754	-2,268	-304	-1	0
1080000	AC PR DPR EL PL SR	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	-32,629	-501	-8,491	-2,575	-4,772	-14,356	-1,924	-9	0
1080000	AC PR DPR EL PL SR	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	-1,825	-28	-475	-144	-267	-803	-108	-1	0
1080000	AC PR DPR EL PL SR	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	-28,648	-440	-7,455	-2,261	-4,190	-12,604	-1,689	-8	0
1080000	AC PR DPR EL PL SR	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	-163	-2	-42	-13	-24	-72	-10	0	0
1080000	AC PR DPR EL PL SR	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	-6,865	-105	-1,786	-542	-1,004	-3,020	-405	-2	0
1080000	AC PR DPR EL PL SR	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	-1,254	-19	-326	-99	-183	-552	-74	0	0
1080000	AC PR DPR EL PL SR	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	-1,509	-23	-393	-119	-221	-664	-89	0	0
1080000	AC PR DPR EL PL SR	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	-17,101	-263	-4,450	-1,350	-2,501	-7,524	-1,009	-5	0
1080000	AC PR DPR EL PL SR	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	-179,701	-2,761	-46,763	-14,182	-26,282	-79,064	-10,598	-51	0
1080000	AC PR DPR EL PL SR	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	-26,517	-407	-6,900	-2,093	-3,878	-11,667	-1,564	-8	0
1080000	AC PR DPR EL PL SR	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	-7,275	-112	-1,893	-574	-1,064	-3,201	-429	-2	0
1080000	AC PR DPR EL PL SR	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	-221	-3	-58	-17	-32	-97	-13	0	0
1080000	AC PR DPR EL PL SR	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	-79	-1	-21	-6	-12	-35	-5	0	0
1080000	AC PR DPR EL PL SR	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	-47	-1	-12	-4	-7	-21	-3	0	0
1080000	AC PR DPR EL PL SR	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	-52,132	-801	-13,566	-4,114	-7,624	-22,937	-3,074	-15	0
1080000	AC PR DPR EL PL SR	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	-21,203	-326	-5,518	-1,673	-3,101	-9,329	-1,250	-6	0
1080000	AC PR DPR EL PL SR	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	-32,504	-499	-8,459	-2,565	-4,754	-14,301	-1,917	-9	0
1080000	AC PR DPR EL PL SR	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	-6,901	-106	-1,796	-545	-1,009	-3,036	-407	-2	0
1080000	AC PR DPR EL PL SR	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	-2,879	-44	-749	-227	-421	-1,266	-170	-1	0
1080000	AC PR DPR EL PL SR	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	-10	0	-3	-1	-1	-4	-1	0	0
1080000	AC PR DPR EL PL SR	3350000	MISC POWER PLANT EQUIP	SG-U	-120	-2	-31	-9	-18	-53	-7	0	0
1080000	AC PR DPR EL PL SR	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	-1,399	-22	-364	-110	-205	-616	-83	0	0
1080000	AC PR DPR EL PL SR	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	-8,893	-137	-2,314	-702	-1,301	-3,913	-524	-3	0
1080000	AC PR DPR EL PL SR	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	-971	-15	-253	-77	-142	-427	-57	0	0
1080000	AC PR DPR EL PL SR	3403000	WATER RIGHTS - OTHER PRODUCTION	SG	0	0	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3410000	STRUCTURES & IMPROVEMENTS	SG	-59,047	-907	-15,366	-4,660	-8,636	-25,979	-3,482	-17	0
1080000	AC PR DPR EL PL SR	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	-3,764	-58	-979	-297	-550	-1,656	-222	-1	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3430000	PRIME MOVERS	SG	-934,788	-14,365	-243,256	-73,774	-136,716	-411,283	-55,129	-265	0
1080000	AC PR DPR EL PL SR	3440000	GENERATORS	SG	-121,112	-1,861	-31,516	-9,558	-17,713	-53,286	-7,143	-34	0
1080000	AC PR DPR EL PL SR	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	-84,769	-1,303	-22,059	-6,690	-12,398	-37,296	-4,999	-24	0
1080000	AC PR DPR EL PL SR	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	-3,710	-57	-965	-293	-543	-1,632	-219	-1	0
1080000	AC PR DPR EL PL SR	3502000	LAND RIGHTS	SG	-48,240	-741	-12,553	-3,807	-7,055	-21,225	-2,845	-14	0
1080000	AC PR DPR EL PL SR	3520000	STRUCTURES & IMPROVEMENTS	SG	-48,587	-747	-12,644	-3,835	-7,106	-21,377	-2,865	-14	0
1080000	AC PR DPR EL PL SR	3530000	STATION EQUIPMENT	SG	-444,208	-6,826	-115,595	-35,057	-64,967	-195,441	-26,197	-126	0
1080000	AC PR DPR EL PL SR	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	-38,229	-587	-9,948	-3,017	-5,591	-16,820	-2,255	-11	0
1080000	AC PR DPR EL PL SR	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	-5,542	-85	-1,442	-437	-811	-2,438	-327	-2	0
1080000	AC PR DPR EL PL SR	3540000	TOWERS AND FIXTURES	SG	-354,184	-5,443	-92,168	-27,952	-51,801	-155,832	-20,888	-100	0
1080000	AC PR DPR EL PL SR	3550000	POLES AND FIXTURES	SG	-358,629	-5,511	-93,325	-28,303	-52,451	-157,788	-21,150	-102	0
1080000	AC PR DPR EL PL SR	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	-510,969	-7,852	-132,968	-40,326	-74,731	-224,813	-30,134	-145	0
1080000	AC PR DPR EL PL SR	3570000	UNDERGROUND CONDUIT	SG	-1,036	-16	-270	-82	-152	-456	-61	0	0
1080000	AC PR DPR EL PL SR	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	-2,552	-39	-664	-201	-373	-1,123	-150	-1	0
1080000	AC PR DPR EL PL SR	3590000	ROADS AND TRAILS	SG	-5,024	-77	-1,307	-396	-735	-2,210	-296	-1	0
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	CA	-737	-737	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	IDU	-629	0	0	0	0	0	-629	0	0
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	OR	-2,963	0	-2,963	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	UT	-3,260	0	0	0	0	-3,260	0	0	0
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	WA	-193	0	0	-193	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	WYP	-1,339	0	0	0	-1,339	0	0	0	0
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	WYU	-1,112	0	0	0	-1,112	0	0	0	0
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	CA	-1,441	-1,441	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	IDU	-746	0	0	0	0	0	-746	0	0
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	OR	-7,889	0	-7,889	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	UT	-12,356	0	0	0	0	-12,356	0	0	0
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WA	-1,217	0	0	-1,217	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WYP	-3,819	0	0	0	-3,819	0	0	0	0
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WYU	-679	0	0	0	-679	0	0	0	0
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	CA	-8,045	-8,045	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	IDU	-12,525	0	0	0	0	0	-12,525	0	0
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	OR	-82,677	0	-82,677	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	UT	-117,966	0	0	0	0	-117,966	0	0	0
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WA	-22,760	0	0	-22,760	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WYP	-40,048	0	0	0	-40,048	0	0	0	0
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WYU	-3,516	0	0	0	-3,516	0	0	0	0
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	-220	-220	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	-166	0	0	0	0	0	-166	0	0
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	-1,205	0	-1,205	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	-1,497	0	0	0	0	-1,497	0	0	0
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	-384	0	0	-384	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	-743	0	0	0	-743	0	0	0	0
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	-25	0	0	0	-25	0	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	CA	-40,088	-40,088	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	IDU	-40,708	0	0	0	0	0	-40,708	0	0
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	OR	-264,471	0	-264,471	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	UT	-157,437	0	0	0	0	-157,437	0	0	0
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WA	-71,494	0	0	-71,494	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WYP	-69,909	0	0	0	-69,909	0	0	0	0
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WYU	-15,667	0	0	0	-15,667	0	0	0	0
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	-19,446	-19,446	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	-17,347	0	0	0	0	0	-17,347	0	0
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	-133,533	0	-133,533	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	-86,653	0	0	0	0	-86,653	0	0	0
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	-34,522	0	0	-34,522	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	-37,817	0	0	0	-37,817	0	0	0	0
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	-5,115	0	0	0	-5,115	0	0	0	0
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	CA	-12,336	-12,336	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	IDU	-4,507	0	0	0	0	0	-4,507	0	0
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	OR	-45,984	0	-45,984	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	UT	-82,954	0	0	0	0	-82,954	0	0	0
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WA	-11,353	0	0	-11,353	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WYP	-10,739	0	0	0	-10,739	0	0	0	0
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WYU	-3,116	0	0	0	-3,116	0	0	0	0
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	-14,394	-14,394	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	-14,115	0	0	0	0	0	-14,115	0	0
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	-88,409	0	-88,409	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	-231,377	0	0	0	0	-231,377	0	0	0
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	-13,801	0	0	-13,801	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	-25,647	0	0	0	-25,647	0	0	0	0
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	-15,270	0	0	0	-15,270	0	0	0	0
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	CA	-31,364	-31,364	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	IDU	-29,217	0	0	0	0	0	-29,217	0	0
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	OR	-237,388	0	-237,388	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	UT	-134,136	0	0	0	0	-134,136	0	0	0
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WA	-61,336	0	0	-61,336	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WYP	-43,425	0	0	0	-43,425	0	0	0	0
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WYU	-6,921	0	0	0	-6,921	0	0	0	0
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	CA	-3,125	-3,125	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	IDU	-5,023	0	0	0	0	0	-5,023	0	0
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	OR	-37,535	0	-37,535	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	UT	-40,684	0	0	0	0	-40,684	0	0	0
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WA	-8,899	0	0	-8,899	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WYP	-6,017	0	0	0	-6,017	0	0	0	0
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WYU	-926	0	0	0	-926	0	0	0	0
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	CA	-6,435	-6,435	0	0	0	0	0	0	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	IDU	-13,386	0	0	0	0	0	-13,386	0	0
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	OR	-93,611	0	-93,611	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	UT	-70,497	0	0	0	0	-70,497	0	0	0
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WA	-20,627	0	0	-20,627	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WYP	-15,316	0	0	0	-15,316	0	0	0	0
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WYU	-4,205	0	0	0	-4,205	0	0	0	0
1080000	AC PR DPR EL PL SR	3700000	METERS	CA	-466	-466	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3700000	METERS	IDU	-10,386	0	0	0	0	0	-10,386	0	0
1080000	AC PR DPR EL PL SR	3700000	METERS	OR	-9,286	0	-9,286	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3700000	METERS	UT	-45,211	0	0	0	0	-45,211	0	0	0
1080000	AC PR DPR EL PL SR	3700000	METERS	WA	-5,457	0	0	-5,457	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3700000	METERS	WYP	-5,335	0	0	0	-5,335	0	0	0	0
1080000	AC PR DPR EL PL SR	3700000	METERS	WYU	-1,254	0	0	0	-1,254	0	0	0	0
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	CA	-212	-212	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	-141	0	0	0	0	0	-141	0	0
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	OR	-2,110	0	-2,110	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	UT	-3,336	0	0	0	0	-3,336	0	0	0
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	WA	-361	0	0	-361	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	-890	0	0	0	-890	0	0	0	0
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	-149	0	0	0	-149	0	0	0	0
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	-601	-601	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	-461	0	0	0	0	0	-461	0	0
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	-11,198	0	-11,198	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	-12,321	0	0	0	0	-12,321	0	0	0
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	-2,218	0	0	-2,218	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	-3,576	0	0	0	-3,576	0	0	0	0
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	-1,153	0	0	0	-1,153	0	0	0	0
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	IDU	-4	0	0	0	0	0	-4	0	0
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	SG	-1	0	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	UT	-32	0	0	0	0	-32	0	0	0
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	WYP	-14	0	0	0	-14	0	0	0	0
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	WYU	-6	0	0	0	-6	0	0	0	0
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	CA	-750	-750	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	CN	-2,311	-55	-722	-160	-172	-1,105	-97	0	0
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	IDU	-4,895	0	0	0	0	0	-4,895	0	0
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	OR	-10,709	0	-10,709	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SE	-364	-5	-91	-27	-58	-158	-24	0	0
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SG	-2,886	-44	-751	-228	-422	-1,270	-170	-1	0
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SO	-31,171	-696	-8,483	-2,400	-4,238	-13,559	-1,789	-6	0
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	UT	-12,577	0	0	0	0	-12,577	0	0	0
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WA	-7,415	0	0	-7,415	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WYP	-1,508	0	0	0	-1,508	0	0	0	0
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WYU	-1,384	0	0	0	-1,384	0	0	0	0

Exhibit PAC/1302
McCoy/406

Depreciation Reserve
Balances as of June 2019
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	3910000	OFFICE FURNITURE	CA	-81	-81	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	CN	-922	-22	-288	-64	-68	-441	-39	0	0
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	IDU	-29	0	0	0	0	0	-29	0	0
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	OR	-980	0	-980	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SE	-3	0	-1	0	0	-1	0	0	0
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SG	-694	-11	-181	-55	-101	-305	-41	0	0
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SO	-7,979	-178	-2,171	-614	-1,085	-3,471	-458	-2	0
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	UT	-278	0	0	0	0	-278	0	0	0
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WA	-38	0	0	-38	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WYP	-296	0	0	0	-296	0	0	0	0
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WYU	-11	0	0	0	-11	0	0	0	0
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	-21	-21	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	-1,410	-34	-440	-98	-105	-674	-59	0	0
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	-135	0	0	0	0	0	-135	0	0
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	-315	0	-315	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	-2	0	0	0	0	-1	0	0	0
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	-455	-7	-118	-36	-66	-200	-27	0	0
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	-15,297	-341	-4,163	-1,178	-2,080	-6,654	-878	-3	0
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	-307	0	0	0	0	-307	0	0	0
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	-101	0	0	-101	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	-830	0	0	0	-830	0	0	0	0
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	-18	0	0	0	-18	0	0	0	0
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	CN	0	0	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	IDU	-1	0	0	0	0	0	-1	0	0
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	OR	-1	0	-1	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	SG	-32	0	-8	-3	-5	-14	-2	0	0
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	SO	-37	-1	-10	-3	-5	-16	-2	0	0
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	UT	-2	0	0	0	0	-2	0	0	0
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	WYP	-2	0	0	0	-2	0	0	0	0
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	WYU	-2	0	0	0	-2	0	0	0	0
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	CA	-33	-33	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	IDU	-143	0	0	0	0	0	-143	0	0
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	OR	-966	0	-966	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SE	-35	-1	-9	-3	-6	-15	-2	0	0
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	-279	-4	-73	-22	-41	-123	-16	0	0
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	-344	-8	-94	-26	-47	-149	-20	0	0
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	-1,433	0	0	0	0	-1,433	0	0	0
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	-137	0	0	-137	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	WYP	-210	0	0	0	-210	0	0	0	0
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	OR	-29	0	-29	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	SG	-30	0	-8	-2	-4	-13	-2	0	0
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	SO	-62	-1	-17	-5	-8	-27	-4	0	0
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	UT	-136	0	0	0	0	-136	0	0	0

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Depreciation Reserve
Balances as of June 2019
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	3920200	MID AND FULL SIZE AUTOMOBILES	WA	-15	0	0	-15	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	WYP	-29	0	0	0	-29	0	0	0	0
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	CA	-279	-279	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	-796	0	0	0	0	0	-796	0	0
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	-3,215	0	-3,215	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	-106	-2	-27	-8	-17	-46	-7	0	0
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	-4,420	-68	-1,150	-349	-646	-1,945	-261	-1	0
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	-778	-17	-212	-60	-106	-339	-45	0	0
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	-4,153	0	0	0	0	-4,153	0	0	0
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	-712	0	0	-712	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYP	-660	0	0	0	-660	0	0	0	0
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	-211	0	0	0	-211	0	0	0	0
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	-479	-479	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	-1,180	0	0	0	0	0	-1,180	0	0
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	-6,222	0	-6,222	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	-156	-2	-39	-12	-25	-68	-10	0	0
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	-3,178	-49	-827	-251	-465	-1,398	-187	-1	0
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	-303	-7	-82	-23	-41	-132	-17	0	0
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	-7,522	0	0	0	0	-7,522	0	0	0
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	-1,622	0	0	-1,622	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYP	-1,419	0	0	0	-1,419	0	0	0	0
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	-325	0	0	0	-325	0	0	0	0
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	OR	-80	0	-80	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	SE	-3	0	-1	0	0	-1	0	0	0
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	SG	-1,947	-30	-507	-154	-285	-857	-115	-1	0
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	UT	-95	0	0	0	0	-95	0	0	0
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	CA	-174	-174	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	IDU	-361	0	0	0	0	0	-361	0	0
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	OR	-1,198	0	-1,198	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	SE	-18	0	-5	-1	-3	-8	-1	0	0
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	SG	-526	-8	-137	-42	-77	-231	-31	0	0
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	SO	-205	-5	-56	-16	-28	-89	-12	0	0
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	UT	-1,962	0	0	0	0	-1,962	0	0	0
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	WA	-279	0	0	-279	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	WYP	-929	0	0	0	-929	0	0	0	0
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	WYU	-195	0	0	0	-195	0	0	0	0
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	-51	-51	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	-47	0	0	0	0	0	-47	0	0
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	-198	0	-198	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SE	-4	0	-1	0	-1	-2	0	0	0
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SG	-313	-5	-81	-25	-46	-137	-18	0	0
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	-20	0	-6	-2	-3	-9	-1	0	0
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	-127	0	0	0	0	-127	0	0	0

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Depreciation Reserve
Balances as of June 2019
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	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WA	-33	0	0	-33	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYP	-95	0	0	0	-95	0	0	0	0
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	-10	0	0	0	-10	0	0	0	0
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	-179	0	-179	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	-231	-4	-60	-18	-34	-102	-14	0	0
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	-182	-4	-49	-14	-25	-79	-10	0	0
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	-570	0	0	0	0	-570	0	0	0
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	-134	0	0	-134	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	WYP	-48	0	0	0	-48	0	0	0	0
1080000	AC PR DPR EL PL SR	3923000	TRANSPORTATION EQUIPMENT	SO	-879	-20	-239	-68	-120	-382	-50	0	0
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	CA	-97	-97	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	IDU	-239	0	0	0	0	0	-239	0	0
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	OR	-1,400	0	-1,400	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	SG	-2,569	-39	-669	-203	-376	-1,131	-152	-1	0
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	SO	-125	-3	-34	-10	-17	-54	-7	0	0
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	UT	-1,576	0	0	0	0	-1,576	0	0	0
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	WA	-357	0	0	-357	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	WYP	-517	0	0	0	-517	0	0	0	0
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	WYU	-1	0	0	0	-1	0	0	0	0
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	-415	-415	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	-1,000	0	0	0	0	0	-1,000	0	0
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	-5,288	0	-5,288	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	-69	-1	-17	-5	-11	-30	-5	0	0
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	-12,808	-197	-3,333	-1,011	-1,873	-5,635	-755	-4	0
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	-1,495	-33	-407	-115	-203	-650	-86	0	0
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	-6,825	0	0	0	0	-6,825	0	0	0
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	-1,569	0	0	-1,569	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	-1,882	0	0	0	-1,882	0	0	0	0
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	-291	0	0	0	-291	0	0	0	0
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	CA	-137	-137	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	IDU	-662	0	0	0	0	0	-662	0	0
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	OR	-3,498	0	-3,498	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	SE	-551	-8	-138	-41	-88	-239	-36	0	0
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	SG	-3,579	-55	-931	-282	-523	-1,575	-211	-1	0
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	SO	-2,400	-54	-653	-185	-326	-1,044	-138	0	0
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	UT	-3,482	0	0	0	0	-3,482	0	0	0
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WA	-653	0	0	-653	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WYP	-1,137	0	0	0	-1,137	0	0	0	0
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WYU	-95	0	0	0	-95	0	0	0	0
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	CA	-801	-801	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	IDU	-1,334	0	0	0	0	0	-1,334	0	0
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	OR	-5,371	0	-5,371	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SG	-214	-3	-56	-17	-31	-94	-13	0	0

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Depreciation Reserve
Balances as of June 2019
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	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SO	-737	-16	-201	-57	-100	-321	-42	0	0
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	UT	-4,385	0	0	0	0	-4,385	0	0	0
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WA	-1,369	0	0	-1,369	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYP	-1,931	0	0	0	-1,931	0	0	0	0
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYU	-317	0	0	0	-317	0	0	0	0
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	CA	-97	-97	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	-66	0	0	0	0	0	-66	0	0
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	OR	-396	0	-396	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	-75	-1	-20	-6	-11	-33	-4	0	0
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	-271	0	0	0	0	-271	0	0	0
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	-88	0	0	0	-88	0	0	0	0
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	CA	-592	-592	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	-576	0	0	0	0	0	-576	0	0
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	-4,606	0	-4,606	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	-556	-9	-145	-44	-81	-245	-33	0	0
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SO	-780	-17	-212	-60	-106	-339	-45	0	0
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	-4,366	0	0	0	0	-4,366	0	0	0
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WA	-1,656	0	0	-1,656	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYP	-938	0	0	0	-938	0	0	0	0
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYU	-241	0	0	0	-241	0	0	0	0
1080000	AC PR DPR EL PL SR	3961000	CRANES	OR	-180	0	-180	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3961000	CRANES	SG	-1,511	-23	-393	-119	-221	-665	-89	0	0
1080000	AC PR DPR EL PL SR	3961000	CRANES	UT	-1	0	0	0	0	-1	0	0	0
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	OR	-343	0	-343	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SG	-8,227	-126	-2,141	-649	-1,203	-3,620	-485	-2	0
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SO	-487	-11	-132	-37	-66	-212	-28	0	0
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	-565	0	0	0	0	-565	0	0	0
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WYP	-97	0	0	0	-97	0	0	0	0
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	CA	-438	-438	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	-578	0	0	0	0	0	-578	0	0
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	-4,148	0	-4,148	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	-152	-2	-40	-12	-22	-67	-9	0	0
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	-485	-11	-132	-37	-66	-211	-28	0	0
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	UT	-5,309	0	0	0	0	-5,309	0	0	0
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WA	-1,045	0	0	-1,045	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	-1,015	0	0	0	-1,015	0	0	0	0
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	-162	0	0	0	-162	0	0	0	0
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	CA	-218	-218	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	IDU	-378	0	0	0	0	0	-378	0	0
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	OR	-940	0	-940	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SE	-109	-2	-27	-8	-17	-47	-7	0	0
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SG	-2,620	-40	-682	-207	-383	-1,153	-155	-1	0
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	-190	-4	-52	-15	-26	-82	-11	0	0

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Depreciation Reserve
Balances as of June 2019
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	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	UT	-1,706	0	0	0	0	-1,706	0	0	0
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WA	-503	0	0	-503	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYP	-433	0	0	0	-433	0	0	0	0
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYU	-225	0	0	0	-225	0	0	0	0
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	CA	-2,357	-2,357	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	CN	-1,628	-39	-508	-113	-121	-779	-68	0	0
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	IDU	-4,147	0	0	0	0	0	-4,147	0	0
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	OR	-32,134	0	-32,134	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	SE	-108	-2	-27	-8	-17	-47	-7	0	0
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	SG	-68,694	-1,056	-17,876	-5,421	-10,047	-30,223	-4,051	-19	0
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	SO	-38,652	-863	-10,519	-2,976	-5,255	-16,813	-2,218	-8	0
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	UT	-25,617	0	0	0	0	-25,617	0	0	0
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	WA	-6,054	0	0	-6,054	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	WYP	-9,402	0	0	0	-9,402	0	0	0	0
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	WYU	-2,116	0	0	0	-2,116	0	0	0	0
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	CA	-191	-191	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	IDU	-220	0	0	0	0	0	-220	0	0
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	OR	-1,663	0	-1,663	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	SE	-52	-1	-13	-4	-8	-23	-3	0	0
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	SG	-2,501	-38	-651	-197	-366	-1,100	-147	-1	0
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	SO	-370	-8	-101	-28	-50	-161	-21	0	0
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	UT	-1,309	0	0	0	0	-1,309	0	0	0
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	WA	-382	0	0	-382	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	WYP	-506	0	0	0	-506	0	0	0	0
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	WYU	-70	0	0	0	-70	0	0	0	0
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	CA	-23	-23	0	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	CN	-43	-1	-13	-3	-3	-21	-2	0	0
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	IDU	-37	0	0	0	0	0	-37	0	0
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	OR	-484	0	-484	0	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SE	-3	0	-1	0	0	-1	0	0	0
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SG	-1,262	-19	-328	-100	-185	-555	-74	0	0
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SO	-1,276	-28	-347	-98	-173	-555	-73	0	0
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	UT	-450	0	0	0	0	-450	0	0	0
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WA	-83	0	0	-83	0	0	0	0	0
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WYP	-73	0	0	0	-73	0	0	0	0
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WYU	-15	0	0	0	-15	0	0	0	0
1080000 Total					**-10,063,813**	**-253,441**	**-2,908,165**	**-825,562**	**-1,365,755**	**-4,134,216**	**-574,721**	**-1,954**	**0**
1083000	AC PR DPR-REMOVAL	288351	Reg Liab Contra - Carbon Decomm - ID	IDU	1,213	0	0	0	0	0	1,213	0	0
1083000	AC PR DPR-REMOVAL	288353	Reg Liab Contra - Carbon Decomm - UT	UT	8,775	0	0	0	0	8,775	0	0	0
1083000	AC PR DPR-REMOVAL	288355	Reg Liab Contra - Carbon Decomm - WY	WYP	714	0	0	0	714	0	0	0	0
1083000 Total					**10,702**	**0**	**0**	**0**	**714**	**8,775**	**1,213**	**0**	**0**
1085000	AC PR DPR-ACCRUAL	145129	BUILDINGS - ACCUMULATED DEPRECIATION-NON	SO	1,385	31	377	107	188	602	79	0	0
1085000	AC PR DPR-ACCRUAL	145131	Accum Depr - Hydro - ID Klamath Adj	OTHER	1,054	0	0	0	0	0	0	0	1,054

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Depreciation Reserve
Balances as of June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1085000	AC PR DPR-ACCRUAL	145134	Accum Depr - Hydro - WY Klamath Adj	OTHER	2,522	0	0	0	0	0	0	0	2,522
1085000	AC PR DPR-ACCRUAL	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-P	-5,844	-90	-1,521	-461	-855	-2,571	-345	-2	0
1085000	AC PR DPR-ACCRUAL	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-U	-610	-9	-159	-48	-89	-268	-36	0	0
1085000	AC PR DPR-ACCRUAL	145139	PRODUCTION PLANT-ACCUM DEPRECIATION	SG	14,223	219	3,701	1,122	2,080	6,258	839	4	0
1085000	AC PR DPR-ACCRUAL	145149	TRANSMISSION PLANT ACCUMULATED DEPR NON-	SG	3,890	60	1,012	307	569	1,711	229	1	0
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	CA	67	67	0	0	0	0	0	0	0
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	IDU	150	0	0	0	0	0	150	0	0
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	OR	1,007	0	1,007	0	0	0	0	0	0
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	UT	1,649	0	0	0	0	1,649	0	0	0
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WA	353	0	0	353	0	0	0	0	0
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WYU	349	0	0	0	349	0	0	0	0
1085000 Total					**20,194**	**277**	**4,418**	**1,379**	**2,242**	**7,381**	**917**	**4**	**3,576**
Grand Total					**-10,032,917**	**-253,164**	**-2,903,747**	**-824,182**	**-1,362,799**	**-4,118,060**	**-572,591**	**-1,951**	**3,576**

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Amortization Reserve
Balances as of June 2019
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	-926	0	0	0	0	0	-926	0	0
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	SG	-5,527	-85	-1,438	-436	-808	-2,432	-326	-2	0
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	SG-P	-105,334	-1,619	-27,411	-8,313	-15,405	-46,344	-6,212	-30	0
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	SG-U	-6,524	-100	-1,698	-515	-954	-2,871	-385	-2	0
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	UT	30,430	0	0	0	0	30,430	0	0	0
1110000	AC PR AMR EL PT SR	3031040	INTANGIBLE PLANT	OR	-104	0	-104	0	0	0	0	0	0
1110000	AC PR AMR EL PT SR	3031040	INTANGIBLE PLANT	SG	-14,771	-227	-3,844	-1,166	-2,160	-6,499	-871	-4	0
1110000	AC PR AMR EL PT SR	3031040	INTANGIBLE PLANT	UT	-21	0	0	0	0	-21	0	0	0
1110000	AC PR AMR EL PT SR	3031040	INTANGIBLE PLANT	WYP	-55	0	0	0	-55	0	0	0	0
1110000	AC PR AMR EL PT SR	3031050	REGIONAL CONST MGMT SYS	SO	-10,950	-244	-2,980	-843	-1,489	-4,763	-628	-2	0
1110000	AC PR AMR EL PT SR	3031080	FUEL MGMT SYSTEM	SO	-3,293	-73	-896	-253	-448	-1,432	-189	-1	0
1110000	AC PR AMR EL PT SR	3031230	AUTOMATE POLE CARD SYSTEM	SO	-4,410	-98	-1,200	-339	-600	-1,918	-253	-1	0
1110000	AC PR AMR EL PT SR	3031680	DISTRIBUTION AUTOMATION PILOT	SO	-13,817	-308	-3,760	-1,064	-1,879	-6,010	-793	-3	0
1110000	AC PR AMR EL PT SR	3031760	RECORD CENTER MGMT SOFTWARE	SO	-291	-6	-79	-22	-40	-127	-17	0	0
1110000	AC PR AMR EL PT SR	3031830	CUSTOMER SERVICE SYSTEM	CN	-113,413	-2,718	-35,404	-7,866	-8,418	-54,240	-4,766	0	0
1110000	AC PR AMR EL PT SR	3032040	SAP	SO	-152,640	-3,406	-41,542	-11,751	-20,754	-66,396	-8,760	-31	0
1110000	AC PR AMR EL PT SR	3032220	ENTERPRISE DATA WRHSE - BI RPTG TOOL	SO	-1,660	-37	-452	-128	-226	-722	-95	0	0
1110000	AC PR AMR EL PT SR	3032270	ENTERPRISE DATA WAREHOUSE	SO	-5,877	-131	-1,599	-452	-799	-2,556	-337	-1	0
1110000	AC PR AMR EL PT SR	3032330	FIELDNET PRO METER READING SYST -HRP REP	SO	-2,908	-65	-791	-224	-395	-1,265	-167	-1	0
1110000	AC PR AMR EL PT SR	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	-1,953	-44	-531	-150	-265	-849	-112	0	0
1110000	AC PR AMR EL PT SR	3032360	2002 GRID NET POWER COST MODELING	SO	-8,947	-200	-2,435	-689	-1,217	-3,892	-513	-2	0
1110000	AC PR AMR EL PT SR	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	-10,490	-234	-2,855	-808	-1,426	-4,563	-602	-2	0
1110000	AC PR AMR EL PT SR	3032510	OPERATIONS MAPPING SYSTEM	SO	-10,386	-232	-2,827	-800	-1,412	-4,518	-596	-2	0
1110000	AC PR AMR EL PT SR	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	-1,892	-42	-515	-146	-257	-823	-109	0	0
1110000	AC PR AMR EL PT SR	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	-2,392	-53	-651	-184	-325	-1,040	-137	0	0
1110000	AC PR AMR EL PT SR	3032600	SINGLE PERSON SCHEDULING	SO	-12,958	-289	-3,527	-998	-1,762	-5,637	-744	-3	0
1110000	AC PR AMR EL PT SR	3032640	TIBCO SOFTWARE	SO	-5,531	-123	-1,505	-426	-752	-2,406	-317	-1	0
1110000	AC PR AMR EL PT SR	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	-1,592	-24	-414	-126	-233	-700	-94	0	0
1110000	AC PR AMR EL PT SR	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	-84	-1	-22	-7	-12	-37	-5	0	0
1110000	AC PR AMR EL PT SR	3032740	GADSBY INTANGIBLE ASSETS	SG	-3	0	-1	0	0	-1	0	0	0
1110000	AC PR AMR EL PT SR	3032760	SWIFT 2 IMPROVEMENTS	SG	-6,414	-99	-1,669	-506	-938	-2,822	-378	-2	0
1110000	AC PR AMR EL PT SR	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	-187	-3	-49	-15	-27	-82	-11	0	0
1110000	AC PR AMR EL PT SR	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	-59	-1	-15	-5	-9	-26	-3	0	0
1110000	AC PR AMR EL PT SR	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG-U	-10	0	-3	-1	-1	-4	-1	0	0
1110000	AC PR AMR EL PT SR	3032830	VCPRO - VISUALCOMPUSETPRO XEROX CUST STM	SO	-2,401	-54	-653	-185	-326	-1,044	-138	0	0
1110000	AC PR AMR EL PT SR	3032860	WEB SOFTWARE	SO	-2,680	-60	-729	-206	-364	-1,166	-154	-1	0
1110000	AC PR AMR EL PT SR	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	-2,787	-43	-725	-220	-408	-1,226	-164	-1	0
1110000	AC PR AMR EL PT SR	3032990	P8DM - FILENET P8 DOCUMENT MANAGEMENT (E	SO	-5,310	-119	-1,445	-409	-722	-2,310	-305	-1	0
1110000	AC PR AMR EL PT SR	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	-25,807	-397	-6,716	-2,037	-3,774	-11,354	-1,522	-7	0
1110000	AC PR AMR EL PT SR	3033170	GTX VERSION 7 SOFTWARE	CN	-4,636	-111	-1,447	-322	-344	-2,217	-195	0	0
1110000	AC PR AMR EL PT SR	3033190	ITRON METER READING SOFTWARE	CN	-5,868	-141	-1,832	-407	-436	-2,807	-247	0	0

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Amortization Reserve
Balances as of June 2019
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	3033210	ARCFM SOFTWARE	SO	-3,211	-72	-874	-247	-437	-1,397	-184	-1	0
1110000	AC PR AMR EL PT SR	3033220	MONARCH EMS/SCADA	SO	-9,271	-207	-2,523	-714	-1,261	-4,033	-532	-2	0
1110000	AC PR AMR EL PT SR	3033230	VREALIZE VMWARE - SHARED	SO	-642	-14	-175	-49	-87	-279	-37	0	0
1110000	AC PR AMR EL PT SR	3033240	IEE - Itron Enterprise Addition	CN	-1,752	-42	-547	-122	-130	-838	-74	0	0
1110000	AC PR AMR EL PT SR	3033250	AMI Metering Software	CN	-6,276	-150	-1,959	-435	-466	-3,001	-264	0	0
1110000	AC PR AMR EL PT SR	3033260	Big Data & Analytics	SO	-134	-3	-37	-10	-18	-58	-8	0	0
1110000	AC PR AMR EL PT SR	3033300	SECID - CUST SECURE WEB LOGIN	CN	-1,085	-26	-339	-75	-81	-519	-46	0	0
1110000	AC PR AMR EL PT SR	3033310	C&T - ENERGY TRADING SYSTEM	SO	-14,460	-323	-3,935	-1,113	-1,966	-6,290	-830	-3	0
1110000	AC PR AMR EL PT SR	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	-9,934	-153	-2,585	-784	-1,453	-4,371	-586	-3	0
1110000	AC PR AMR EL PT SR	3033370	DISTRIBUTION INTANGIBLES	WYP	-30	0	0	0	-30	0	0	0	0
1110000	AC PR AMR EL PT SR	3033380	MISCELLANEOUS SMALL SOFTWARE PACKAGES	SG	-675	-10	-176	-53	-99	-297	-40	0	0
1110000	AC PR AMR EL PT SR	3033390	RMT TRADE SYSTEM	SO	-634	-14	-173	-49	-86	-276	-36	0	0
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	CA	-3	-3	0	0	0	0	0	0	0
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	CN	-10	0	-3	-1	-1	-5	0	0	0
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	IDU	-5	0	0	0	0	0	-5	0	0
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	OR	-2	0	-2	0	0	0	0	0	0
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	SG	-22,726	-349	-5,914	-1,794	-3,324	-9,999	-1,340	-6	0
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	SO	-490	-11	-133	-38	-67	-213	-28	0	0
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	UT	-13	0	0	0	0	-13	0	0	0
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	WA	-5	0	0	-5	0	0	0	0	0
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	WYP	-68	0	0	0	-68	0	0	0	0
1110000	AC PR AMR EL PT SR	3035320	HYDRO PLANT INTANGIBLES	SG	-472	-7	-123	-37	-69	-208	-28	0	0
1110000	AC PR AMR EL PT SR	3035320	HYDRO PLANT INTANGIBLES	SG-P	-87	-1	-23	-7	-13	-38	-5	0	0
1110000	AC PR AMR EL PT SR	3035322	ACD–Call Center Automated Call Distribut	CN	-4,030	-97	-1,258	-280	-299	-1,928	-169	0	0
1110000	AC PR AMR EL PT SR	3035330	OATI-OASIS INTERFACE	SO	-1,240	-28	-337	-95	-169	-539	-71	0	0
1110000	AC PR AMR EL PT SR	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	-2,516	-39	-655	-199	-368	-1,107	-148	-1	0
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	-506	-506	0	0	0	0	0	0	0
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	IDU	-334	0	0	0	0	0	-334	0	0
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	-4,177	0	-4,177	0	0	0	0	0	0
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	-3,443	-77	-937	-265	-468	-1,498	-198	-1	0
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	-18	0	0	0	0	-18	0	0	0
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	-1,691	0	0	-1,691	0	0	0	0	0
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	-4,352	0	0	0	-4,352	0	0	0	0
1110000 Total					**-618,767**	**-13,520**	**-180,648**	**-50,079**	**-84,752**	**-253,615**	**-36,035**	**-118**	**0**
Grand Total					**-618,767**	**-13,520**	**-180,648**	**-50,079**	**-84,752**	**-253,615**	**-36,035**	**-118**	**0**

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Deferred Income Tax Balance
Balances as of June 2019
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	319	319	0	0	0	0	0	0	0
1900000	ACM DEF INCM TAXES	287062	DTA 705.347 - ID - Protected PP&E ARAM	IDU	762	0	0	0	0	0	762	0	0
1900000	ACM DEF INCM TAXES	287063	DTA 705.348 - OR - Protected PP&E ARAM	OR	3,617	0	3,617	0	0	0	0	0	0
1900000	ACM DEF INCM TAXES	287064	DTA 705.349 - UT - Protected PP&E ARAM	UT	6,501	0	0	0	0	6,501	0	0	0
1900000	ACM DEF INCM TAXES	287065	DTA 705.350 - WA - Protected PP&E ARAM	WA	930	0	0	930	0	0	0	0	0
1900000	ACM DEF INCM TAXES	287066	DTA 705.351 - WY - Protected PP&E ARAM	WYU	2,125	0	0	0	2,125	0	0	0	0
1900000 Total					**14,253**	**319**	**3,617**	**930**	**2,125**	**6,501**	**762**	**0**	**0**
1901000	ACCUM DEF INC TAX	287051	DTA 705.340 RL-Income Tax Deferral-CA	OTHER	1,188	0	0	0	0	0	0	0	1,188
1901000	ACCUM DEF INC TAX	287052	DTA 705.341 RL-Income Tax Deferral-ID	OTHER	269	0	0	0	0	0	0	0	269
1901000	ACCUM DEF INC TAX	287053	DTA 705.342 RL-Income Tax Deferral-OR	OTHER	12,316	0	0	0	0	0	0	0	12,316
1901000	ACCUM DEF INC TAX	287054	DTA 705.343 RL-Income Tax Deferral-UT	OTHER	740	0	0	0	0	0	0	0	740
1901000	ACCUM DEF INC TAX	287055	DTA 705.344 RL-Income Tax Deferral-WA	OTHER	2,147	0	0	0	0	0	0	0	2,147
1901000	ACCUM DEF INC TAX	287056	DTA 705.345 RL-Income Tax Deferral-WY	OTHER	1,309	0	0	0	0	0	0	0	1,309
1901000	ACCUM DEF INC TAX	287191	DTA 705.280 RL Excess Def Inc Taxes CA	CA	273	273	0	0	0	0	0	0	0
1901000	ACCUM DEF INC TAX	287192	DTA 705.281 RL Excess Def Inc Taxes ID	IDU	382	0	0	0	0	0	382	0	0
1901000	ACCUM DEF INC TAX	287193	DTA 705.282 RL Excess Def Inc Taxes OR	OR	3,877	0	3,877	0	0	0	0	0	0
1901000	ACCUM DEF INC TAX	287195	DTA 705.284 RL Excess Def Inc Taxes WA	WA	326	0	0	326	0	0	0	0	0
1901000	ACCUM DEF INC TAX	287196	DTA 705.285 RL Excess Def Inc Taxes WY	WYU	2,940	0	0	0	2,940	0	0	0	0
1901000	ACCUM DEF INC TAX	287197	DTA 705.286 RL Excess Def Inc Tax FERC	FERC	4	0	0	0	0	0	0	4	0
1901000	ACCUM DEF INC TAX	287199	DTA 220.101 Bad Debt	BADDEBT	-41	-2	-15	-5	-3	-14	-2	0	0
1901000	ACCUM DEF INC TAX	287200	DTA 705.267 RL-WA Decoup Mech	OTHER	544	0	0	0	0	0	0	0	544
1901000	ACCUM DEF INC TAX	287206	DTA 415.710 RL-WA Accel Depr	WA	8,197	0	0	8,197	0	0	0	0	0
1901000	ACCUM DEF INC TAX	287209	DTA 705.266 RL-Energy Savings Assist-CA	OTHER	124	0	0	0	0	0	0	0	124
1901000	ACCUM DEF INC TAX	287210	DTA 505.115 - Sales & Use Tax Audit Exp	OTHER	62	0	0	0	0	0	0	0	62
1901000	ACCUM DEF INC TAX	287211	DTA 425.226 - Deferred Revenue Other	OTHER	280	0	0	0	0	0	0	0	280
1901000	ACCUM DEF INC TAX	287212	DTA 705.245-RL-OR Dir Acc 5 yr Opt Out	OTHER	1,134	0	0	0	0	0	0	0	1,134
1901000	ACCUM DEF INC TAX	287214	DTA 910.245 - Contra Rec Joint Owners	SO	382	9	104	29	52	166	22	0	0
1901000	ACCUM DEF INC TAX	287216	DTA 605.715 Trapper Mine Contract Oblig	SE	1,596	23	401	120	255	692	105	1	0
1901000	ACCUM DEF INC TAX	287219	DTA 715.810 Chehalis Mitigation Oblig	SG	126	2	33	10	18	55	7	0	0
1901000	ACCUM DEF INC TAX	287220	DTA 720.560 Pension Liab UMWA Withdraw	SE	28,304	412	7,105	2,128	4,523	12,271	1,856	9	0
1901000	ACCUM DEF INC TAX	287225	DTA 605.103 ARO/Reg Diff - Trojan - WA	WA	-64	0	0	-64	0	0	0	0	0
1901000	ACCUM DEF INC TAX	287227	DTA 705.531 RL UT Solar Feed-in Tar - NC	OTHER	5,900	0	0	0	0	0	0	0	5,900
1901000	ACCUM DEF INC TAX	287229	DTA 705.527 RL CA Solar Feed-in Tar - NC	OTHER	153	0	0	0	0	0	0	0	153
1901000	ACCUM DEF INC TAX	287231	DTA 705.519 RL WA Def NPC - Noncurrent	OTHER	3,658	0	0	0	0	0	0	0	3,658
1901000	ACCUM DEF INC TAX	287233	DTA 705.515 RL OR Def NPC - Noncurrent	OTHER	8,189	0	0	0	0	0	0	0	8,189
1901000	ACCUM DEF INC TAX	287237	DTA 705.755 RL-NONCURRENT RECLASS-OTHER	OTHER	27	0	0	0	0	0	0	0	27
1901000	ACCUM DEF INC TAX	287238	DTA 705.420 RL - CA GHG Allowance Rev	OTHER	1,097	0	0	0	0	0	0	0	1,097
1901000	ACCUM DEF INC TAX	287240	DTA 605.301 Environmental Liab- Reg	SO	14,284	319	3,888	1,100	1,942	6,214	820	3	0
1901000	ACCUM DEF INC TAX	287253	DTA 705.400 Reg Lia - OR Inj & Dam Reser	OR	2,156	0	2,156	0	0	0	0	0	0
1901000	ACCUM DEF INC TAX	287257	DTA 705.453 Reg Lia - ID Property Ins Re	IDU	205	0	0	0	0	0	205	0	0
1901000	ACCUM DEF INC TAX	287258	DTA 705.454 Reg Lia - UT Property Ins Re	UT	1,764	0	0	0	0	1,764	0	0	0
1901000	ACCUM DEF INC TAX	287259	DTA 705.455 Reg Lia - WY Property Ins Re	WYP	233	0	0	0	233	0	0	0	0
1901000	ACCUM DEF INC TAX	287270	Valuation Allowance for DTA	SO	-676	-15	-184	-52	-92	-294	-39	0	0

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Deferred Income Tax Balance
Balances as of June 2019
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	287271	DTA 705.336 RL - Sale of RECs - UT	OTHER	74	0	0	0	0	0	0	0	74
1901000	ACCUM DEF INC TAX	287272	DTA 705.337 RL - Sale of RECs - WY	OTHER	21	0	0	0	0	0	0	0	21
1901000	ACCUM DEF INC TAX	287281	DTA - CA AMT CREDIT	OTHER	255	0	0	0	0	0	0	0	255
1901000	ACCUM DEF INC TAX	287298	DTA 205.210 ERC Impairment Reserve	SE	502	7	126	38	80	217	33	0	0
1901000	ACCUM DEF INC TAX	287299	DTA 705.265 Reg Liab-OR Energy Conservat	OTHER	705	0	0	0	0	0	0	0	705
1901000	ACCUM DEF INC TAX	287302	DTA-610.114 PMI EITF 04-06 PRE STRIPPING	SE	1,565	23	393	118	250	679	103	1	0
1901000	ACCUM DEF INC TAX	287304	DTA 610.146 OR REG ASSET/LIAB CONS	OR	-65	0	-65	0	0	0	0	0	0
1901000	ACCUM DEF INC TAX	287323	DTA 505.400 Bonus Liab. Elec.-Cash Basis	SO	319	7	87	25	43	139	18	0	0
1901000	ACCUM DEF INC TAX	287324	DTA 720.200 Deferred Comp. Accrual - Cas	SO	2,157	48	587	166	293	938	124	0	0
1901000	ACCUM DEF INC TAX	287326	DTA 720.500 Severance Accrual - Cash Ba	SO	219	5	60	17	30	95	13	0	0
1901000	ACCUM DEF INC TAX	287327	DTA 720.300 Pension/Retirement Accrual -	SO	406	9	110	31	55	177	23	0	0
1901000	ACCUM DEF INC TAX	287332	DTA 505.600 Vacation Accrual-Cash Basis	SO	7,019	157	1,910	540	954	3,053	403	1	0
1901000	ACCUM DEF INC TAX	287337	DTA 715.105 MCI F.O.G. WIRE LEASE	SG	434	7	113	34	64	191	26	0	0
1901000	ACCUM DEF INC TAX	287338	DTA415.110 Def Reg Asset-Transmission Sr	SG	519	8	135	41	76	228	31	0	0
1901000	ACCUM DEF INC TAX	287340	DTA 220.100 Bad Debts Allowance - Cash B	BADDEBT	2,760	150	984	342	204	932	147	0	0
1901000	ACCUM DEF INC TAX	287341	DTA 910.530 Injuries & Damages Accrual -	SO	4,003	89	1,089	308	544	1,741	230	1	0
1901000	ACCUM DEF INC TAX	287370	DTA 425.215 Unearned Joint Use Pole Cont	SNPD	74	3	20	5	8	36	4	0	0
1901000	ACCUM DEF INC TAX	287371	DTA 930.100 Oregon BETC Credits	SG	1,599	25	416	126	234	704	94	0	0
1901000	ACCUM DEF INC TAX	287389	DTA 610.145 RL - DSM	OTHER	7,207	0	0	0	0	0	0	0	7,207
1901000	ACCUM DEF INC TAX	287414	DTA 505.700 RT BONUS	SO	244	5	66	19	33	106	14	0	0
1901000	ACCUM DEF INC TAX	287415	DTA 205.200 M&S INV	SNPD	721	26	193	44	74	347	37	0	0
1901000	ACCUM DEF INC TAX	287417	DTA 605.710 ACCRUED FINAL RECLAMATION	OTHER	1,441	0	0	0	0	0	0	0	1,441
1901000	ACCUM DEF INC TAX	287430	DTA 505.125 Accrued Royalties	SE	1,865	27	468	140	298	809	122	1	0
1901000	ACCUM DEF INC TAX	287437	DTA Net Operating Loss Carryforwrd-State	SO	72,551	1,619	19,745	5,585	9,865	31,559	4,164	15	0
1901000	ACCUM DEF INC TAX	287441	DTA 605.100 Trojan Decom Cost-Regulatory	TROJD	1,323	20	342	104	197	581	80	0	0
1901000	ACCUM DEF INC TAX	287449	DTA Federal Detriment of State NOL	SO	-15,275	-341	-4,157	-1,176	-2,077	-6,644	-877	-3	0
1901000	ACCUM DEF INC TAX	287453	DTA 610.143 WA PRGRM	OTHER	-144	0	0	0	0	0	0	0	-144
1901000	ACCUM DEF INC TAX	287460	DTA 720.800 FAS 158 Pension Liability	SO	24,181	540	6,581	1,862	3,288	10,518	1,388	5	0
1901000	ACCUM DEF INC TAX	287461	DTA 720.810 FAS 158 Post-Retirement Liab	SO	759	17	207	58	103	330	44	0	0
1901000	ACCUM DEF INC TAX	287473	DTA 705.270 Reg Liab	OTHER	601	0	0	0	0	0	0	0	601
1901000	ACCUM DEF INC TAX	287474	DTA 705.271 Reg Liab	OTHER	111	0	0	0	0	0	0	0	111
1901000	ACCUM DEF INC TAX	287475	DTA 705.272 Reg Liab	OTHER	59	0	0	0	0	0	0	0	59
1901000	ACCUM DEF INC TAX	287476	DTA 705.273 Reg Liab	OTHER	2,346	0	0	0	0	0	0	0	2,346
1901000	ACCUM DEF INC TAX	287477	DTA 705.274 Reg Liab	OTHER	66	0	0	0	0	0	0	0	66
1901000	ACCUM DEF INC TAX	287478	DTA 705.275 Reg Liab	OTHER	137	0	0	0	0	0	0	0	137
1901000	ACCUM DEF INC TAX	287479	DTA 105.221 Saf Har	SG	18,753	288	4,880	1,480	2,743	8,251	1,106	5	0
1901000	ACCUM DEF INC TAX	287482	DTA 205.025 PMI Fuel Cost Adjustment	SE	83	1	21	6	13	36	5	0	0
1901000	ACCUM DEF INC TAX	287486	DTA 415.926 RL-Depreciation Decrease-OR	OTHER	1,442	0	0	0	0	0	0	0	1,442
1901000	ACCUM DEF INC TAX	287487	DTA 415.927 RL-Depreciation Decrease-WA	WA	-2	0	0	-2	0	0	0	0	0
1901000	ACCUM DEF INC TAX	287491	DTA - BETC CREDIT CARRYFORWARD	SG	5,176	80	1,347	408	757	2,277	305	1	0
1901000	ACCUM DEF INC TAX	287576	DTL 430.110 Reg Asset Balance Reclass	OTHER	-3,063	0	0	0	0	0	0	0	-3,063
1901000	ACCUM DEF INC TAX	287681	DTL 920.110 BRIDGER EXTRACTION TAXES PAY	SE	2,194	32	551	165	351	951	144	1	0
1901000	ACCUM DEF INC TAX	287706	DTL 610.100 COAL MINE DEVT PMI	SE	-425	-6	-107	-32	-68	-184	-28	0	0

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Deferred Income Tax Balance
Balances as of June 2019
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	287720	DTL 610.100 PMI DEV'T COST AMORT	SE	-569	-8	-143	-43	-91	-247	-37	0	0
1901000	ACCUM DEF INC TAX	287722	DTL 505.510 PMI VAC ACCRUAL	SE	199	3	50	15	32	86	13	0	0
1901000	ACCUM DEF INC TAX	287723	DTL 205.411 PMI SEC. 263A	SE	34	0	8	3	5	15	2	0	0
1901000	ACCUM DEF INC TAX	287726	DTL PMI PP&E	SE	-12,829	-187	-3,220	-964	-2,050	-5,562	-841	-4	0
1901000	ACCUM DEF INC TAX	287735	DTL 910.905 PMI COST DEPLETION	SE	-912	-13	-229	-69	-146	-395	-60	0	0
1901000	ACCUM DEF INC TAX	287937	DTA 505.601 PMI - Sick Leave Accrual	SE	11	0	3	1	2	5	1	0	0
1901000	ACCUM DEF INC TAX	287941	DTL 430.111 Reg Asset - SB 1149 Balance	OTHER	-5,176	0	0	0	0	0	0	0	-5,176
1901000 Total					**229,082**	**3,660**	**49,936**	**21,185**	**26,032**	**72,824**	**10,185**	**42**	**45,218**
1901090	FAS109 DEF TAX ASS	287374	DTA 100.105 FAS 109 Deferred Tax Liabili	WA	186	0	0	186	0	0	0	0	0
1901090 Total					**186**	**0**	**0**	**186**	**0**	**0**	**0**	**0**	**0**
2811000	AC DEF TAX-ACCL AM	287960	DTL 105.128 Accel Depr Pollution Cntrl F	SG	-177,049	-2,721	-46,073	-13,973	-25,894	-77,897	-10,441	-50	0
2811000 Total					**-177,049**	**-2,721**	**-46,073**	**-13,973**	**-25,894**	**-77,897**	**-10,441**	**-50**	**0**
2820000	AC DEF INCTX-PROPT	287704	DTL 105.143/165 Basis Diff - Intangibles	SO	-1,113	-25	-303	-86	-151	-484	-64	0	0
2820000 Total					**-1,113**	**-25**	**-303**	**-86**	**-151**	**-484**	**-64**	**0**	**0**
2821000	AC DEF TAX-UTILITY	286605	DTL 105.136 PP&E	DITBAL	-384	-9	-95	-25	-56	-170	-22	-1	0
2821000	AC DEF TAX-UTILITY	286691	DTL Non-Prot PP&E EDIT - CA	CA	-6,749	-6,749	0	0	0	0	0	0	0
2821000	AC DEF TAX-UTILITY	286692	DTL Non-Prot PP&E EDIT - ID	IDU	-9,653	0	0	0	0	0	-9,653	0	0
2821000	AC DEF TAX-UTILITY	286693	DTL Non-Prot PP&E EDIT - OR	OR	-93,280	0	-93,280	0	0	0	0	0	0
2821000	AC DEF TAX-UTILITY	286694	DTL Non-Prot PP&E EDIT - WA	WA	-20,866	0	0	-20,866	0	0	0	0	0
2821000	AC DEF TAX-UTILITY	286695	DTL Non-Prot PP&E EDIT - WY	WYU	-38,491	0	0	0	-38,491	0	0	0	0
2821000	AC DEF TAX-UTILITY	286697	DTL Non-Prot PP&E EDIT - FERC	FERC	-3,769	0	0	0	0	0	0	-3,769	0
2821000	AC DEF TAX-UTILITY	287221	DTA 415.933 RL Contra-Carbon Decomm-ID	IDU	-298	0	0	0	0	0	-298	0	0
2821000	AC DEF TAX-UTILITY	287222	DTA 415.934 RL Contra-Carbon Decomm-UT	UT	-2,157	0	0	0	0	-2,157	0	0	0
2821000	AC DEF TAX-UTILITY	287223	DTA 415.935 RL Contra-Carbon Decomm-WY	WYP	-176	0	0	0	-176	0	0	0	0
2821000	AC DEF TAX-UTILITY	287301	DTA 105.471 UT Klamath Relicensing	OTHER	8,681	0	0	0	0	0	0	0	8,681
2821000	AC DEF TAX-UTILITY	287605	DTL PP&E Powertax	DITBAL	-3,983,530	-88,699	-983,075	-258,261	-584,103	-1,766,679	-232,558	-9,466	0
2821000	AC DEF TAX-UTILITY	287607	DTL PMI PP&E	SE	-7,148	-104	-1,794	-537	-1,142	-3,099	-469	-2	0
2821000	AC DEF TAX-UTILITY	287608	DTL Safe Harbor Lease Cholla	SG	-842	-13	-219	-66	-123	-370	-50	0	0
2821000	AC DEF TAX-UTILITY	287766	DTL 610.100N Amort	SO	66	1	18	5	9	29	4	0	0
2821000	AC DEF TAX-UTILITY	287771	DTL 110.205 SRC tax depletion	SE	151	2	38	11	24	65	10	0	0
2821000	AC DEF TAX-UTILITY	287928	DTL 425.310 Hydro Relicensing Obligation	OTHER	-3,863	0	0	0	0	0	0	0	-3,863
2821000 Total					**-4,162,309**	**-95,569**	**-1,078,408**	**-279,739**	**-624,059**	**-1,772,382**	**-243,037**	**-13,238**	**4,818**
2831000	AC DEF IN TX UTIL	286901	DTL 415.938 RA - Carbon Plt Dec/Inv-CA	CA	13	13	0	0	0	0	0	0	0
2831000	AC DEF IN TX UTIL	286903	DTL 320.271 Contra RA-Pension Plan CTG	SO	202	5	55	16	27	88	12	0	0
2831000	AC DEF IN TX UTIL	286905	DTL 415.530 RA-ID 2017 Protocol-MSP Def	IDU	-55	0	0	0	0	0	-55	0	0
2831000	AC DEF IN TX UTIL	286906	DTL 415.531 RA-UT 2017 Protocol-MSP Def	UT	-2,705	0	0	0	0	-2,705	0	0	0
2831000	AC DEF IN TX UTIL	286907	DTL 415.532 RA-WY 2017 Protocol-MSP Def	WYP	-787	0	0	0	-787	0	0	0	0
2831000	AC DEF IN TX UTIL	286908	DTL 210.201 Property Tax	GPS	-3,392	-76	-923	-261	-461	-1,475	-195	-1	0
2831000	AC DEF IN TX UTIL	286909	DTL 720.815 Post-Retirement Asset	SO	-611	-14	-166	-47	-83	-266	-35	0	0
2831000	AC DEF IN TX UTIL	286910	DTL 415.200 RA-OR Transp Elect PilotPgm	OTHER	-96	0	0	0	0	0	0	0	-96
2831000	AC DEF IN TX UTIL	286911	DTL 415.430 - RA-Transp Elect Pilot-CA	OTHER	109	0	0	0	0	0	0	0	109
2831000	AC DEF IN TX UTIL	286912	DTL 415.431 - RA-Transp Elect Pilot-WA	OTHER	-10	0	0	0	0	0	0	0	-10
2831000	AC DEF IN TX UTIL	286913	DTL 415.720 RA-OR Community Solar	OTHER	-39	0	0	0	0	0	0	0	-39

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Deferred Income Tax Balance
Balances as of June 2019
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	287570	DTL 415.701 CA Deferred Intervenor Fundi	OTHER	-11	0	0	0	0	0	0	0	-11
2831000	AC DEF IN TX UTIL	287571	DTL 415.702 Reg Asset-Lake Side Liq. Dam	WYU	-190	0	0	0	-190	0	0	0	0
2831000	AC DEF IN TX UTIL	287576	DTL 430.110 REG ASSET RECLASS	OTHER	-4,144	0	0	0	0	0	0	0	-4,144
2831000	AC DEF IN TX UTIL	287591	DTL 415.301 Environmental Clean-up Accrl	WA	508	0	0	508	0	0	0	0	0
2831000	AC DEF IN TX UTIL	287593	DTL 415.874 Deferred Net Power Costs-WY	OTHER	-1,796	0	0	0	0	0	0	0	-1,796
2831000	AC DEF IN TX UTIL	287596	DTL 415.892 Deferred Net Power Costs - I	OTHER	-5,896	0	0	0	0	0	0	0	-5,896
2831000	AC DEF IN TX UTIL	287597	DTL 415.703 Goodnoe Hills Liquidation Da	WYP	-76	0	0	0	-76	0	0	0	0
2831000	AC DEF IN TX UTIL	287601	DTL 415.677 RA Pref Stock Redemption WA	OTHER	-15	0	0	0	0	0	0	0	-15
2831000	AC DEF IN TX UTIL	287614	DTL 430.100 Weatherization	OTHER	2,266	0	0	0	0	0	0	0	2,266
2831000	AC DEF IN TX UTIL	287634	DTL 415.300 Environmental Clean-up Accru	SO	-21,555	-481	-5,866	-1,659	-2,931	-9,376	-1,237	-4	0
2831000	AC DEF IN TX UTIL	287639	DTL 415.510 WA Disallowed Colstrip 3-Wri	WA	-20	0	0	-20	0	0	0	0	0
2831000	AC DEF IN TX UTIL	287640	DTL 415.680 Deferred Intervener Funding	OTHER	-286	0	0	0	0	0	0	0	-286
2831000	AC DEF IN TX UTIL	287647	DTL 425.100 IDAHO DEFERRED REGULATORY EX	IDU	-16	0	0	0	0	0	-16	0	0
2831000	AC DEF IN TX UTIL	287650	DTL 205.100 Coal Pile Inventory Adjustme	SE	0	0	0	0	0	0	0	0	0
2831000	AC DEF IN TX UTIL	287653	DTL 425.250 TGS Buyout	SG	-2	0	-1	0	0	-1	0	0	0
2831000	AC DEF IN TX UTIL	287661	DTL 425.360 Hermiston Swap	SG	-721	-11	-188	-57	-105	-317	-43	0	0
2831000	AC DEF IN TX UTIL	287662	DTL 210.100 Prepaid Taxes - OR PUC	OR	-745	0	-745	0	0	0	0	0	0
2831000	AC DEF IN TX UTIL	287664	DTL 210.120 Prepaid Taxes - UT PUC	UT	-1,526	0	0	0	0	-1,526	0	0	0
2831000	AC DEF IN TX UTIL	287665	DTL 210.130 Prepaid Taxes - ID PUC	IDU	-89	0	0	0	0	0	-89	0	0
2831000	AC DEF IN TX UTIL	287669	DTL 210.180 PRE MEM	SO	-950	-21	-258	-73	-129	-413	-55	0	0
2831000	AC DEF IN TX UTIL	287675	DTL 740.100 Post Merger Loss-Reacq Debt	SNP	-1,048	-22	-276	-78	-142	-470	-60	0	0
2831000	AC DEF IN TX UTIL	287708	DTL 210.200 PREPAID PROPERTY TAXES	GPS	-3,298	-74	-898	-254	-448	-1,435	-189	-1	0
2831000	AC DEF IN TX UTIL	287738	DTL 320.270 Reg Asset FAS 158 Pension	SO	-107,608	-2,401	-29,286	-8,284	-14,631	-46,808	-6,176	-22	0
2831000	AC DEF IN TX UTIL	287739	DTL 320.280 Reg Asset FAS 158 Post-Ret	SO	501	11	136	39	68	218	29	0	0
2831000	AC DEF IN TX UTIL	287747	DTL 705.240 CA Energy Program	OTHER	-97	0	0	0	0	0	0	0	-97
2831000	AC DEF IN TX UTIL	287770	DTL 120.205 TRAPPER MINE-EQUITY EARNINGS	OTHER	-1,143	0	0	0	0	0	0	0	-1,143
2831000	AC DEF IN TX UTIL	287781	DTL 415.870 Def CA	OTHER	-1,354	0	0	0	0	0	0	0	-1,354
2831000	AC DEF IN TX UTIL	287840	DTL 415.410 RA Energy West Mining	SE	-66,911	-973	-16,796	-5,030	-10,692	-29,010	-4,388	-22	0
2831000	AC DEF IN TX UTIL	287841	DTL 415.411 ContraRA DeerCreekAband CA	CA	601	601	0	0	0	0	0	0	0
2831000	AC DEF IN TX UTIL	287842	DTL 415.412 ContraRA DeerCreekAband ID	IDU	467	0	0	0	0	0	467	0	0
2831000	AC DEF IN TX UTIL	287843	DTL 415.413 ContraRA DeerCreekAband OR	OR	1,939	0	1,939	0	0	0	0	0	0
2831000	AC DEF IN TX UTIL	287844	DTL 415.414 ContraRA DeerCreekAband UT	UT	592	0	0	0	0	592	0	0	0
2831000	AC DEF IN TX UTIL	287845	DTL 415.415 ContraRA DeerCreekAband WA	WA	2,697	0	0	2,697	0	0	0	0	0
2831000	AC DEF IN TX UTIL	287846	DTL 415.416 ContraRA DeerCreekAband WY	WYU	92	0	0	0	92	0	0	0	0
2831000	AC DEF IN TX UTIL	287848	DTL 320.281 RA Post-Ret Settlement Loss	SO	-1,549	-35	-422	-119	-211	-674	-89	0	0
2831000	AC DEF IN TX UTIL	287849	DTL 415.424 ContraRA DeerCreekAband	SE	24,640	358	6,185	1,852	3,938	10,683	1,616	8	0
2831000	AC DEF IN TX UTIL	287850	DTL 415.425 Contra RA UMWA Pension	OTHER	1,168	0	0	0	0	0	0	0	1,168
2831000	AC DEF IN TX UTIL	287851	DTL 415.417 Contra RA UMWA Pension CA	OTHER	444	0	0	0	0	0	0	0	444
2831000	AC DEF IN TX UTIL	287855	DTL 415.421 Contra RA UMWA Pension WA	OTHER	1,991	0	0	0	0	0	0	0	1,991
2831000	AC DEF IN TX UTIL	287857	DTL 415.545 Reg Asset WA Merwin Project	OTHER	1	0	0	0	0	0	0	0	1
2831000	AC DEF IN TX UTIL	287858	DTL 415.676 RA Pref Stock Redemption-WY	OTHER	-33	0	0	0	0	0	0	0	-33
2831000	AC DEF IN TX UTIL	287860	DTL 415.855 Reg Asset-CA-Jan10 Storm Cos	OTHER	-355	0	0	0	0	0	0	0	-355
2831000	AC DEF IN TX UTIL	287861	DTL 415.857 Reg Asset-ID-Def Overburden	OTHER	-113	0	0	0	0	0	0	0	-113

PACIFICORP

Deferred Income Tax Balance
Balances as of June 2019
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	287864	DTL 415.852 Powerdale Decom Cost Amort-I	IDU	-10	0	0	0	0	0	-10	0	0
2831000	AC DEF IN TX UTIL	287868	DTL 415.858 Reg Asset-WY-Def Overburden	WYP	-317	0	0	0	-317	0	0	0	0
2831000	AC DEF IN TX UTIL	287871	DTL 415.866 Reg Asset-OR Solar Feed-In T	OTHER	-1,213	0	0	0	0	0	0	0	-1,213
2831000	AC DEF IN TX UTIL	287882	DTL 415.876 Deferred Net Power Costs-OR	OTHER	-715	0	0	0	0	0	0	0	-715
2831000	AC DEF IN TX UTIL	287887	DTL 415.881 Def of Excess RECs UT	OTHER	-197	0	0	0	0	0	0	0	-197
2831000	AC DEF IN TX UTIL	287888	DTL 415.882 Def of Excess RECs WA	OTHER	-10	0	0	0	0	0	0	0	-10
2831000	AC DEF IN TX UTIL	287889	DTL 415.883 Def of Excess RECs WY	OTHER	-128	0	0	0	0	0	0	0	-128
2831000	AC DEF IN TX UTIL	287896	DTL 415.875 Def Net Power Cost - UT	OTHER	-8,894	0	0	0	0	0	0	0	-8,894
2831000	AC DEF IN TX UTIL	287897	DTL 425.400 RA - UT Klamath Relicensing	OTHER	-3,406	0	0	0	0	0	0	0	-3,406
2831000	AC DEF IN TX UTIL	287899	DTL 415.878 RA-UT Liq Damages	UT	-125	0	0	0	0	-125	0	0	0
2831000	AC DEF IN TX UTIL	287903	DTL 415.879 RA-Liq Damages N2-WY	WYP	-20	0	0	0	-20	0	0	0	0
2831000	AC DEF IN TX UTIL	287906	DTL 415.863 RA-UT Subscriber Solar Prog	UT	-421	0	0	0	0	-421	0	0	0
2831000	AC DEF IN TX UTIL	287907	DTL 210.185-Prepaid Aircraft Maint Cost	SG	-9	0	-2	-1	-1	-4	-1	0	0
2831000	AC DEF IN TX UTIL	287908	DTL 210.190 - Prepaid Water Rights	SG	-120	-2	-31	-9	-18	-53	-7	0	0
2831000	AC DEF IN TX UTIL	287917	DTL 705.451 - RL - OR Property Ins Res	OR	-2,854	0	-2,854	0	0	0	0	0	0
2831000	AC DEF IN TX UTIL	287919	DTL 425.105 RA-OR Asset Sale Gain GB-NC	OTHER	-173	0	0	0	0	0	0	0	-173
2831000	AC DEF IN TX UTIL	287933	DTL 320.282-RA PostRet Sttmt Loss-CC-UT	UT	-344	0	0	0	0	-344	0	0	0
2831000	AC DEF IN TX UTIL	287934	DTL 320.283-RA PostRet Sttmt Loss-CC-WY	WYU	-3	0	0	0	-3	0	0	0	0
2831000	AC DEF IN TX UTIL	287935	DTL 415.936 RA - Carbon Plt Decom/Inv	SG	-848	-13	-221	-67	-124	-373	-50	0	0
2831000	AC DEF IN TX UTIL	287939	DTL 415.115 RA-UT STEP Pilot Program	OTHER	3,935	0	0	0	0	0	0	0	3,935
2831000	AC DEF IN TX UTIL	287942	DTL 430.112 Reg Asset - Other - Balance	OTHER	-322	0	0	0	0	0	0	0	-322
2831000	AC DEF IN TX UTIL	287971	DTL 415.868 RA UT Solar Incentive Prog	OTHER	-3,935	0	0	0	0	0	0	0	-3,935
2831000	AC DEF IN TX UTIL	287977	DTL 415.885 RA-NONCURRENT RECLASS-OTHER	OTHER	-27	0	0	0	0	0	0	0	-27
2831000	AC DEF IN TX UTIL	287978	DTL 415.906 RA OR RECs in Rate - NC	OTHER	-3	0	0	0	0	0	0	0	-3
2831000	AC DEF IN TX UTIL	287981	DTL 415.920 RA-Depreciation Increase-ID	IDU	-9	0	0	0	0	0	-9	0	0
2831000	AC DEF IN TX UTIL	287982	DTL 415.921 RA-Depreciation Increase-UT	UT	-378	0	0	0	0	-378	0	0	0
2831000	AC DEF IN TX UTIL	287983	DTL 415.922 RA-Depreciation Increase-WY	WYP	-1,305	0	0	0	-1,305	0	0	0	0
2831000	AC DEF IN TX UTIL	287984	DTL 415.923 RA-Carbon Unrec Plant - ID	IDU	-177	0	0	0	0	0	-177	0	0
2831000	AC DEF IN TX UTIL	287985	DTL 415.924 RA-Carbon Unrec Plant - UT	UT	-1,270	0	0	0	0	-1,270	0	0	0
2831000	AC DEF IN TX UTIL	287986	DTL 415.925 RA-Carbon Unrec Plant - WY	WYP	-427	0	0	0	-427	0	0	0	0
2831000	AC DEF IN TX UTIL	287996	DTL 415.675 RA Pref Stock Redemption-UT	OTHER	-96	0	0	0	0	0	0	0	-96
2831000	AC DEF IN TX UTIL	287997	DTL 415.862 RA-CA Mobile Home Park Conv	OTHER	-49	0	0	0	0	0	0	0	-49
2831000 Total					**-214,877**	**-3,134**	**-50,616**	**-10,849**	**-28,976**	**-85,863**	**-10,756**	**-43**	**-24,640**
Grand Total					**-4,311,827**	**-97,469**	**-1,121,848**	**-282,345**	**-650,924**	**-1,857,302**	**-253,351**	**-13,289**	**25,396**

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Investment Tax Credit Balance
Balances as of June 2019
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	285608	JIM BRIDGER RETROFIT ITC - PPL	ITC90	-43	-1	-7	-2	-7	-20	-6	0	0
2551000	ACC DEF ITC - FED	285620	Accum Def ITC - Solar Arrays - 2013	SG	-129	-2	-34	-10	-19	-57	-8	0	0
2551000	ACC DEF ITC - FED	285621	Accum Def ITC - Solar Arrays - 2014	SG	-87	-1	-23	-7	-13	-38	-5	0	0
2551000 Total					**-259**	**-4**	**-63**	**-19**	**-39**	**-115**	**-19**	**0**	**0**
2552000	ACC DEF ITC-IDAHO	285612	Acc Def Idaho ITC-ID situs ATL	IDU	-38	0	0	0	0	0	-38	0	0
2552000 Total					**-38**	**0**	**0**	**0**	**0**	**0**	**-38**	**0**	**0**
Grand Total					**-297**	**-4**	**-63**	**-19**	**-39**	**-115**	**-57**	**0**	**0**

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Customer Advances

Balances as of June 2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-PPL	Utah	Idaho	FERC	Other
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	OR	-919	0	-919	0	0	0	0	0	0
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	SG	-35,071	-539	-9,126	-2,768	-4,143	-15,430	-2,068	-10	0
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	UT	-1,209	0	0	0	0	-1,209	0	0	0
2520000	CUST ADV CONSTRUCT	210553	Transmission Payments Received - Capital	SG	-3,593	-55	-935	-284	-425	-1,581	-212	-1	0
2520000	CUST ADV CONSTRUCT	210556	NET METER FEES-REFUNDABLE	UT	-333	0	0	0	0	-333	0	0	0
2520000	CUST ADV CONSTRUCT	210556	NET METER FEES-REFUNDABLE	WA	-1	0	0	-1	0	0	0	0	0
2520000	CUST ADV CONSTRUCT	285460	Transm Intercon Deposits - w/3rd Party	SG	-20,529	-315	-5,342	-1,620	-2,425	-9,032	-1,211	-6	0
2520000 Total					**-61,656**	**-910**	**-16,323**	**-4,673**	**-6,993**	**-27,586**	**-3,491**	**-17**	**0**
Grand Total					**-61,656**	**-910**	**-16,323**	**-4,673**	**-6,993**	**-27,586**	**-3,491**	**-17**	**0**

REDACTED
Docket No. UE 374
Exhibit PAC/1303
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Shelley E. McCoy

PacifiCorp's Property Tax Estimation Procedure

February 2020

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

REDACTED
Docket No. UE 374
Exhibit PAC/1304
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

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Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Wage and Employee Benefits Wage Escalators

February 2020

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Docket No. UE 374
Exhibit PAC/1305
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Pryor Mountain O&M Adjustment Support

February 2020

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Docket No. UE 374
Exhibit PAC/1306
Witness: Shelley E. McCoy

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IHS Global Insight Escalation Indices

February 2020

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Docket No. UE 374
Exhibit PAC/1307
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Depreciation Expense & Reserves Adjustment Support

February 2020

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Docket No. UE 374
Exhibit PAC/1308
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Other Plant Closure Costs Details Adjustment Support

February 2020

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Docket No. UE 374
Exhibit PAC/1309
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Pro Forma Plant Additions Adjustment Support

February 2020

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Docket No. UE 374
Exhibit PAC/1310
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Repowering Capital Additions Adjustment Support

February 2020

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Docket No. UE 374
Exhibit PAC/1311
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

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Energy Vision 2020 Wind Project Capital Additions Adjustment

Support

February 2020

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Docket No. UE 374
Exhibit PAC/1312
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Generation Plant Removal Adjustment, Cholla Unit 4 Amortization Schedule

February 2020

PacifiCorp
Oregon General Rate Case - December 2021
Cholla Unit 4 Retirement
Amortization of Unrecovered Balances and Closure Costs

Interest Rate, pre-tax WACC from UE-374		9.46%
Amortization Period, January 2021 - April 2025 (months)		52
Oregon allocation of balances and costs	$	61,657,899
Annual collection	$	17,329,776

	Month	Year	Beginning Balance	Amortization	Interest	Ending Balance
1	January	2021	61,657,899	(1,444,148)	480,182	60,693,933
2	February	2021	60,693,933	(1,444,148)	472,586	59,722,371
3	March	2021	59,722,371	(1,444,148)	464,930	58,743,153
4	April	2021	58,743,153	(1,444,148)	457,213	57,756,218
5	May	2021	57,756,218	(1,444,148)	449,436	56,761,507
6	June	2021	56,761,507	(1,444,148)	441,598	55,758,956
7	July	2021	55,758,956	(1,444,148)	433,698	54,748,506
8	August	2021	54,748,506	(1,444,148)	425,735	53,730,093
9	September	2021	53,730,093	(1,444,148)	417,710	52,703,655
10	October	2021	52,703,655	(1,444,148)	409,621	51,669,128
11	November	2021	51,669,128	(1,444,148)	401,469	50,626,450
12	December	2021	50,626,450	(1,444,148)	393,253	49,575,554
13	January	2022	49,575,554	(1,444,148)	384,972	48,516,378
14	February	2022	48,516,378	(1,444,148)	376,625	47,448,855
15	March	2022	47,448,855	(1,444,148)	368,213	46,372,920
16	April	2022	46,372,920	(1,444,148)	359,734	45,288,506
17	May	2022	45,288,506	(1,444,148)	351,189	44,195,547
18	June	2022	44,195,547	(1,444,148)	342,576	43,093,976
19	July	2022	43,093,976	(1,444,148)	333,896	41,983,724
20	August	2022	41,983,724	(1,444,148)	325,147	40,864,723
21	September	2022	40,864,723	(1,444,148)	316,329	39,736,904
22	October	2022	39,736,904	(1,444,148)	307,442	38,600,198
23	November	2022	38,600,198	(1,444,148)	298,484	37,454,534
24	December	2022	37,454,534	(1,444,148)	289,456	36,299,842
25	January	2023	36,299,842	(1,444,148)	280,357	35,136,052
26	February	2023	35,136,052	(1,444,148)	271,187	33,963,090
27	March	2023	33,963,090	(1,444,148)	261,943	32,780,886
28	April	2023	32,780,886	(1,444,148)	252,627	31,589,365
29	May	2023	31,589,365	(1,444,148)	243,238	30,388,455
30	June	2023	30,388,455	(1,444,148)	233,775	29,178,082
31	July	2023	29,178,082	(1,444,148)	224,237	27,958,171
32	August	2023	27,958,171	(1,444,148)	214,624	26,728,647
33	September	2023	26,728,647	(1,444,148)	204,935	25,489,434
34	October	2023	25,489,434	(1,444,148)	195,170	24,240,456
35	November	2023	24,240,456	(1,444,148)	185,328	22,981,635
36	December	2023	22,981,635	(1,444,137)	175,408	21,712,907
37	January	2024	21,712,907	(1,444,126)	165,411	20,434,191
38	February	2024	20,434,191	(1,444,115)	155,334	19,145,410
39	March	2024	19,145,410	(1,444,104)	145,178	17,846,484

PacifiCorp
Oregon General Rate Case - December 2021
Cholla Unit 4 Retirement
Amortization of Unrecovered Balances and Closure Costs

Interest Rate, pre-tax WACC from UE-374		9.46%
Amortization Period, January 2021 - April 2025 (months)		52
Oregon allocation of balances and costs	$	61,657,899
Annual collection	$	17,329,776

	Month	Year	Beginning Balance	Amortization	Interest	Ending Balance
40	April	2024	17,846,484	(1,444,093)	134,943	16,537,334
41	May	2024	16,537,334	(1,444,082)	124,627	15,217,879
42	June	2024	15,217,879	(1,444,071)	114,229	13,888,037
43	July	2024	13,888,037	(1,444,060)	103,750	12,547,726
44	August	2024	12,547,726	(1,444,049)	93,188	11,196,865
45	September	2024	11,196,865	(1,444,038)	82,543	9,835,371
46	October	2024	9,835,371	(1,444,027)	71,814	8,463,158
47	November	2024	8,463,158	(1,444,016)	61,001	7,080,143
48	December	2024	7,080,143	(1,444,005)	50,103	5,686,241
49	January	2025	5,686,241	(1,443,994)	39,119	4,281,366
50	February	2025	4,281,366	(1,443,983)	28,048	2,865,431
51	March	2025	2,865,431	(1,443,972)	16,891	1,438,350
52	April	2025	1,438,350	(1,443,995)	5,645	(0)
Total				**(75,094,049)**	**13,436,149**	

Docket No. UE 374
Exhibit PAC/1313
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Federal Tax Act Adjustment, Tax Cuts & Jobs Act Deferral Balances Amortization Schedule

February 2020

PacifiCorp
Oregon General Rate Case - December 2021
TCJA Deferral Balances
Amortization of Projected 12/31/20 Balance

Interest Rate, 2020 MBTR	2.63%
Amortization Period (months)	36
Projected Current Tax Benefits Deferral, 12/31/20	(50,643,669)
Projected EDIT Amortization Deferral, 12/31/20	(21,063,266)
Total Projected 12/31/20 Balance	(71,706,935)
Annual rate credit	24,856,584

1	January	2021	(71,706,935)	2,071,382	(154,888)	(69,790,441)
2	February	2021	(69,790,441)	2,071,382	(150,687)	(67,869,746)
3	March	2021	(67,869,746)	2,071,382	(146,478)	(65,944,842)
4	April	2021	(65,944,842)	2,071,382	(142,259)	(64,015,719)
5	May	2021	(64,015,719)	2,071,382	(138,031)	(62,082,368)
6	June	2021	(62,082,368)	2,071,382	(133,794)	(60,144,780)
7	July	2021	(60,144,780)	2,071,382	(129,547)	(58,202,946)
8	August	2021	(58,202,946)	2,071,382	(125,292)	(56,256,855)
9	September	2021	(56,256,855)	2,071,382	(121,026)	(54,306,500)
10	October	2021	(54,306,500)	2,071,382	(116,752)	(52,351,870)
11	November	2021	(52,351,870)	2,071,382	(112,468)	(50,392,956)
12	December	2021	(50,392,956)	2,071,382	(108,175)	(48,429,748)
13	January	2022	(48,429,748)	2,071,382	(103,872)	(46,462,238)
14	February	2022	(46,462,238)	2,071,382	(99,560)	(44,490,416)
15	March	2022	(44,490,416)	2,071,382	(95,238)	(42,514,272)
16	April	2022	(42,514,272)	2,071,382	(90,907)	(40,533,798)
17	May	2022	(40,533,798)	2,071,382	(86,567)	(38,548,982)
18	June	2022	(38,548,982)	2,071,382	(82,217)	(36,559,817)
19	July	2022	(36,559,817)	2,071,382	(77,857)	(34,566,292)
20	August	2022	(34,566,292)	2,071,382	(73,488)	(32,568,398)
21	September	2022	(32,568,398)	2,071,382	(69,109)	(30,566,125)
22	October	2022	(30,566,125)	2,071,382	(64,721)	(28,559,464)
23	November	2022	(28,559,464)	2,071,382	(60,323)	(26,548,405)
24	December	2022	(26,548,405)	2,071,382	(55,915)	(24,532,938)
25	January	2023	(24,532,938)	2,071,382	(51,498)	(22,513,054)
26	February	2023	(22,513,054)	2,071,382	(47,071)	(20,488,744)
27	March	2023	(20,488,744)	2,071,382	(42,635)	(18,459,996)
28	April	2023	(18,459,996)	2,071,382	(38,188)	(16,426,802)
29	May	2023	(16,426,802)	2,071,382	(33,732)	(14,389,153)
30	June	2023	(14,389,153)	2,071,382	(29,266)	(12,347,037)
31	July	2023	(12,347,037)	2,071,382	(24,791)	(10,300,446)
32	August	2023	(10,300,446)	2,071,382	(20,305)	(8,249,369)
33	September	2023	(8,249,369)	2,071,382	(15,810)	(6,193,797)
34	October	2023	(6,193,797)	2,071,382	(11,305)	(4,133,720)
35	November	2023	(4,133,720)	2,071,382	(6,790)	(2,069,128)
36	December	2023	(2,069,128)	2,071,393	(2,265)	0
Total				**74,569,763**	**(2,862,828)**	

Docket No. UE 374
Exhibit PAC/1400
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Robert M. Meredith

February 2020

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ATTACHED EXHIBITS

Exhibit PAC/1401 – Proposed Tariffs

Exhibit PAC/1402 – Unbundled Results of Operations - Summary and Detail

Exhibit PAC/1403 – Functionalized Oregon Results of Operations Report

Exhibit PAC/1404 – Functional Factors

Exhibit PAC/1405 – Ancillary Services Revenue Requirement

Exhibit PAC/1406 – Oregon Marginal Cost of Service Study Summary

Exhibit PAC/1407 – Unbundled Revenue Requirement Allocation

Exhibit PAC/1408 – Oregon Marginal Cost of Service Study

Exhibit PAC/1409 – Target Functionalized Revenues and Billing Determinants

Exhibit PAC/1410 – Estimated Effect of Proposed Rates and Proposed Adjustment Schedules

Exhibit PAC/1411 – Residential Basic Charge Calculation

Exhibit PAC/1412 – Proposed Time of Use Period Justification

Exhibit PAC/1413 – Proposed Schedule 6 Residential Time of Use Pilot Program Rates

Exhibit PAC/1414 – Proposed Schedule 41 Agricultural Pumping Service Time of Use Option Rates

Exhibit PAC/1415 – Proposed Schedule 29 General Service Time of Use Pilot Rates

Exhibit PAC/1416 – Proposed Schedule 218 Interruptible Service Pilot

Exhibit PAC/1417 – Proposed Schedule 219 Real-Time Day-Ahead Pricing Pilot

Exhibit PAC/1418 – Street and Area Light Price Re-Design

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 Robert M. Meredith. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Director, Pricing and Cost of Service.

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science degree in Business Administration and a minor in Economics from Oregon State University. In addition to my formal education, I have attended various industry-related seminars. I have worked for the Company for 15 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over nine years of experience preparing cost of service and pricing related analyses for all of the six states that PacifiCorp serves. In March 2016, I became Manager, Pricing and Cost of Service. In June 2019, I was promoted to my current position.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What are your responsibilities in these proceedings?

A. I am responsible for the Company's proposed revenue requirement for each of the unbundled service categories, the Company's functionalization procedures, the Oregon Marginal Cost Study and the design of the Company's proposed prices in this proceeding. The proposed tariffs incorporate the Company's proposed price increase and are designed consistent with the Commission's rules under OAR 860-038-0200.

I am sponsoring the Company's Oregon electric tariff schedules submitted for approval in this filing. Exhibit PAC/1401 contains the proposed tariffs.

Q. Please summarize your testimony.

A. The overall rate increase proposed by the Company in this case, including the effect of rebalancing the Rate Mitigation Adjustment (RMA) (discussed later in my testimony), is $70.8 million or 5.4 percent.[1] The Company is proposing a base rate spread that is consistent with the cost of service study in this case. Including the effect of all tariff riders, the Company's proposed net rate spread proposes continued use of the RMA to achieve a rate increase on January 1, 2021, where no customer rate class will see a rate increase more than 10.0 percent.

Taking into consideration the requested price change in this case and in the concurrent Transition Adjustment Mechanism (TAM) filed by the Company, the overall requested rate change is a 1.6 percent increase, or about $21.6 million. Table 1 below shows the proposed net bill impact of both filings to the different classes:

Table 1. Net Combined Bill Impact from General Rate Case and Transition Adjustment Mechanism

	GRC	TAM	**Total**
Residential	5.0%	-3.2%	**1.8%**
Commercial and Industrial	6.0%	-4.2%	**1.8%**
Lighting	-18.9%	-7.5%	**-26.4%**
Overall	5.4%	-3.7%	**1.6%**

Rate design/structure changes that the Company proposes in this case include the following:

[1] The net increase of $70.8 million, or 5.4 percent overall on January 1, 2021 consists of the proposed price change including resetting Schedule 299, the Rate Mitigation Adjustment, and the net impact to customers of separate tariff riders for proposed Schedule 195 – Federal Tax Act Adjustment and Schedule 197 – Generation Plant Removal Adjustment.

- Splitting the monthly basic charge into $12 for single-family and $7 for multi-family customers and reducing the differential for tiered rates in half.
- Modernizing time of use periods and increasing the differential between on- and off-peak energy for large non-residential customers.
- Modifying the underlying structure of Company-owned street and area lighting prices to simplify rates and better align the Company's incentives.
- Introduction of several innovative pricing pilots including a residential time of use pilot, a time of use pilot for smaller non-residential customers, and interruptible service and real-time day-ahead pilots for larger non-residential customers.

III. UNBUNDLED CLASS REVENUE REQUIREMENTS

Q. Please identify Exhibit PAC/1402 and explain what it shows.

A. Exhibit PAC/1402 shows the Company's proposed revenue requirement for each of the unbundled service categories required by OAR 860-038-0200: Generation (also referred to as Production), Transmission, Distribution, Ancillary Services, Consumer Services—Billing, Consumer Services—Metering, Consumer Services—Other, Retail Services, and Investment in Public Purposes.

No revenue requirement is shown for the Retail Services or Investment in Public Purposes categories. The Company separately accounts for the costs associated with unregulated retail activities and is not seeking regulatory cost recovery for these items. Public purpose revenues are collected under a separate tariff.

Q. Does the Company include any additional detail within the unbundling of its revenue requirement?

A. Yes. In this case, the Company proposes unbundling a subfunction within Distribution specifically for the Company's provision of lighting equipment that the Company provides for street and area lights. Owning and maintaining lighting equipment is a cost that is only necessary to serve consumers taking service on a limited number of schedules and is easily isolated by Federal Energy Regulatory Commission (FERC) account. Considering changes that the Company proposes for its Company-owned street and area light prices that I will discuss later in my testimony and the Company's intention to transition to more efficient light-emitting diode (LED) technology, it is important for the embedded costs and benefits of Company-owned lights to be tracked and assigned to those consumers who utilize them. This sub-function is listed on Exhibit PAC/1402 as "Distribution - Lighting".

Q. How was the revenue requirement determined for each of the unbundled categories?

A. Rate base balances, revenues and expenses were either assigned or allocated to unbundled categories in accordance with Oregon regulations.[2] Traditional revenue requirement methodology, (i.e., recovery of costs plus a return on rate base), was then used to determine a revenue requirement for each category. Rate base balances, revenues and expenses are from PacifiCorp's Oregon Results of Operations Report, as prepared under the direction of Ms. Shelley E. McCoy. The application of PacifiCorp's proposed rate increase is shown on page 2 of Exhibit PAC/1402.

Q. Please identify Exhibit PAC/1403 and explain what it shows.

A. Page 1 of Exhibit PAC/1403 is the summary page from PacifiCorp's December 2021 Functionalized Oregon Results of Operations Report (Functionalized Oregon Results of Operations Report) and is the basis for the unbundled revenue requirement in

[1] *See* OAR 860-038-0200.

Exhibit PAC/1402. It separates the results of operations into the unbundled categories identified above.

Q. Please explain how the rate base balances, revenues and expenses in the Functionalized Oregon Results of Operations Report were apportioned among the unbundled categories.

A. The detail of PacifiCorp's Functionalized Results of Operations Report by FERC account is found on page 2 through 22 of Exhibit PAC/1403. The functionalization procedures in this case are consistent with those approved in Order 01-787 and implemented in Advice No. 01-020. Functional factors employed in the development of these results are provided in Exhibit PAC/1404.

Q. How did PacifiCorp determine the revenue requirement for Ancillary Services?

A. The revenue requirement for Ancillary Services was estimated by applying PacifiCorp's prices for Regulation and Frequency Response Service, Spinning Reserve Service, and Supplemental Reserve Service to the relevant billing determinants of PacifiCorp's total Oregon retail load. This is shown in Exhibit PAC/1405. The costs associated with providing these services are included in the Generation function. The estimated revenue for Ancillary Services is treated as an offsetting revenue credit against the Generation revenue requirement.

Q. Please identify Exhibit PAC/1406.

A. Exhibit PAC/1406 contains a summary from PacifiCorp's State of Oregon December 2021 Marginal Cost Study (Marginal Cost Study). The Marginal Cost Study is described in more detail later in my testimony.

Q. Please identify Exhibit PAC/1407 and explain what it shows.

A. Page 1 of Exhibit PAC/1407 is the derivation of functionalized class revenue requirements and a comparison with current revenues. This exhibit is based on the results of both the Functionalized Oregon Results of Operations Report and the Marginal Cost Study. Present class revenues are shown on line 1 and megawatt-hours (MWh) are shown on line 2. Full long-run marginal costs for each customer class, separated by function, are shown on lines 4 through 12. Lines 14 through 25 show each class' share of total marginal costs for each function as well as each class' share of revenue and MWh. Lines 28 through 40 show the assignment of functional revenue requirement. The total revenue requirement for each unbundled category, as determined earlier, is shown in the total column. The total for each function is then allocated to a particular customer class based on that class' share of total marginal cost for that function. For example, the residential class accounts for 43.44 percent of generation marginal costs and is assigned 43.44 percent of the generation revenue requirement. Regulatory and franchise fees are considered part of the distribution function; however, for the purpose of assigning cost responsibility, the fees have been broken out separately. Regulatory and franchise fees have been assigned on the basis of class revenue. Lines 42 through 50 compare the total revenue requirement by class to the present class revenues collected from base rates as shown on line 1.

Q. Please explain what is shown on pages 2 and 3 of Exhibit PAC/1407.

A. Pages 2 and 3 of Exhibit PAC/1407 provides a reconciliation between Operating Revenues and Target Revenue Requirement, as shown on page 1 of this exhibit, with those shown in Exhibits PAC/1402 and PAC/1403. Not all customer classes are included in the Marginal Cost Study. Page 2 of Exhibit PAC/1407 accounts for all

Oregon test period revenue sources. Page 3 accounts for all revenue sources included in the Target Revenue Requirement.

IV. MARGINAL COST STUDY

Q. Please describe PacifiCorp's Marginal Cost Study that accompanies this filing.

A. The Marginal Cost Study is found in Exhibit PAC/1408. This study shows, by customer class, PacifiCorp's marginal cost of resources required to produce one additional unit of electricity, or to add one additional customer. Exhibit PAC/1408 contains a marginal cost and circuit model procedures narrative, various summary tables, and supporting calculations.

Q. Is this Marginal Cost Study similar to studies the Company has previously filed?

A. Yes. This study is similar to the cost of service study the Company presented in docket UE 263 (2013 Rate Case), with some notable updates to the methodology which better reflect marginal costs as they exist today. First, the marginal cost of complying with Oregon's renewable portfolio standard (RPS) in the computation of marginal energy-related generation cost was modified to be based on the forecast incremental cost of compliance included with the Company's bi-annual RPS implementation plans. Second, distribution peaks were weighted by the load of substations peaking in each month. Third, the marginal cost of transmission and distribution substations were modified to align with the transmission and distribution deferral credits used for demand-side management modeling in the Company's 2019 Integrated Resource Plan (IRP). Finally, the marginal cost of meter reading was set to zero as a result of the Company's implementation of advanced metering infrastructure (AMI).

Marginal Cost Study Changes: Marginal Cost of RPS Compliance

Q. How was the marginal cost of complying with Oregon's RPS determined?

A. The marginal cost of Oregon RPS Compliance was determined by multiplying the Company's forecast incremental cost of compliance, as calculated and filed in the Company's RPS implementation plan, by the Oregon RPS target percentage for each year.[3] The Company's 2019 RPS Implementation Plan showed that the Company had a negative incremental cost of compliance for each of the forecast years presented (2019 to 2023).[4] For this rate case, the Company therefore assumes zero as the marginal cost of RPS compliance.

Marginal Cost Study Changes: Changes to Distribution Peaks

Q. Why are distribution peaks weighted by the load of substations peaking in each month?

A. Peak load is the key cost-driver of substation equipment. In making distribution investment decisions, engineers use peak-loading on individual circuits and substation transformers. For many of its distribution substations, the Company knows the month and magnitude in megawatts (MW) of peak load. Weighting the 12 monthly distribution coincident peaks by the load of substations peaking in each month provides a more accurate representation of how costs are incurred to serve load, since it reflects the seasonality of when substations peak.

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[3] *See* ORS 469A.100 (4); OAR 860-083-100.
[4] *See In the matter of PacifiCorp, dba Pacific Power, 2021-2023 Renewable Portfolio Standard Implementation Plan,* Docket No. UM 2049, Renewable Portfolio Standard Implementation Plan (Dec. 31, 2019).

Marginal Cost Study Changes: Modifications to Marginal Transmission and Distribution Substation Costs

Q. Please describe the changes made to the calculation of marginal transmission and distribution substation costs.

A. The method of calculating the marginal cost of transmission and distribution substation costs was revised in this study to reflect the methodology used in the Company's IRP to estimate a transmission and distribution deferral benefit for demand-side management. For marginal transmission cost, the difference in this calculation is that the cost of projected transmission additions are divided by the capacity that would be added from these builds instead of the peak load growth projected for the investment horizon, as was done in the Company's previous marginal cost studies. Using the actual capacity added from the equipment as the denominator is a more accurate reflection of the marginal cost of adding transmission than load growth, because transmission investment is often lumpy and built to reliably serve existing load and provide capacity for load growth that will be experienced in the future.

For marginal distribution substation cost, the difference in the calculation is that the incremental substation cost is 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.

Marginal Cost Study Changes: Meter Reading Costs

Q. Why were marginal meter reading costs set to zero in this filing?

A. The majority of the Company's meters in Oregon were replaced with AMI meters by the end of 2019. With AMI technology there is no marginal cost associated with reading meters. While a small percentage of meters are read either by phone or manually for customers who opt-out of AMI or where the AMI mesh network is not fully functional, AMI opt-out manual meter reading costs are recovered directly through fees to customers who elect to opt-out and the telephony costs associated with meter reading are negligible.

Q. How are marginal costs calculated?

A. One-year marginal costs include only changes in operating costs while 10-year and 20-year marginal costs also include the cost of expanding facilities. The costs of these added facilities result in long-run costs that are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. They do not include any demand-related generation, transmission or distribution costs. A detailed description of marginal cost procedures is included in pages 1 through 14 of Exhibit PAC/1408.

Q. Please describe the marginal cost summary tables included in pages 15 through 22 of Exhibit PAC/1408.

A. Tables 1 and 2 of Exhibit PAC/1408 summarize the one-year, 10-year and 20-year marginal costs on a mills-per-kilowatt-hour (kWh) or dollars-per-customer basis.

Table 3 summarizes the unit costs based on the results of the long-run (20-year) marginal cost study. Unit costs are shown for generation, transmission, distribution and various customer service functional categories. Table 3 also includes energy usage, peak demand, and number of customers by customer class for the 12-month period ending December 31, 2021 test period. This information is used to calculate the annual long-run marginal costs by class shown at the bottom of Table 3.

Q. Please explain how generation marginal costs are calculated.

A. Marginal generation costs in this study are based on the Company's currently approved Oregon avoided cost calculations. New resource costs are based on the fixed and variable cost of a combined cycle combustion turbine, which operates as a base load unit. Recognizing that base load generation produces the dual products of capacity and energy, capacity costs are determined using the fixed costs of a simple cycle combustion turbine. Generation energy costs are calculated by combining the remaining fixed and all variable costs of the combined cycle turbine plus the marginal cost of RPS compliance. The marginal cost of RPS compliance is based upon the forecast incremental cost of compliance multiplied by the RPS compliance obligation percentage in each year. The compliance obligation is 20 percent for 2021 to 2024, 27 percent for 2025 to 2029, 35 percent for 2030 to 2034, 45 percent for 2035 to 2039, and 50 percent for 2040 and beyond. Marginal generation capacity and energy costs are summarized on Table 4 of Exhibit PAC/1408.

Q. How are transmission costs calculated?

A. Transmission costs are based on a five-year analysis of forecasted expenditures. Expenditures identified as growth-related are used to develop marginal transmission costs. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand. Bulk power lines are classified both to demand and energy in the same proportions as the long-run marginal costs of generation resources. Marginal transmission costs are summarized on Table 5 of Exhibit PAC/1408.

Q. Please provide a general overview of how marginal distribution costs are determined.

A. Table 6 of Exhibit PAC/1408 provides a unit cost summary by class and load size of marginal distribution costs. Distribution costs are classified into three components: (1) demand-related, shown in dollars per kilowatt (kW)/year; (2) commitment-related, shown in dollars per customer/year; and (3) billing-related, shown in dollars per customer/year. Commitment-related distribution costs consist of the costs of transformers, poles and conductors that are not determined by the level of demand customers place on the system. Demand-related distribution costs include additional costs of larger transformers, substations, poles and conductors with sufficient capacity to serve the level of demand a customer class places on the system.

Q. Please describe how the marginal costs of distribution line transformers are calculated.

A. Marginal transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of the Company's commonly installed transformers. Commitment and demand costs are separated by the nature of this statistical technique. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

Q. Please describe how the marginal costs of distribution circuits are calculated.

A. Marginal costs of distribution poles and wires are calculated using the Company's Distribution Circuit Model. The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics and current cost estimates for Oregon. Customer locations are based on actual customer distances from the substation. The results are segregated into commitment-related and demand-related costs for each customer class. A detailed description of the updated circuit model is also included in the marginal cost procedures on pages 5 through 14 of Exhibit PAC/1408.

Q. How are substation marginal costs calculated?

A. Marginal substation costs are determined using the per kW cost of substation additions being considered for a five-year period. The cost per kW is determined by dividing the growth-related distribution substation investment in the capital budget horizon by the related increase in substation capacity. Substation marginal costs are classified entirely to demand and are allocated to customer classes based on the distribution peak load for each class weighted by the load of substations peaking in each month.

Q. What is included in the service drop category?

A. The service drop category includes the marginal cost of service drops with associated operation and maintenance (O&M). Current typical installed costs for service drops are determined for each customer load size.

Q. What is included in the metering category?

A. The metering category includes the marginal cost of metering equipment with associated O&M. Current typical installed metering costs are determined for each customer load size by analyzing service requirements, such as single- or three-phase service and voltage level. Meter O&M is based on historical expenditures.

Q. What is included in the billing and customer service/other categories?

A. This category includes the costs of billing, payment processing and debt recovery, meter reading expense, and all the remaining customer accounting and customer service activities. As discussed earlier in my testimony, marginal meter reading expense is assumed to be zero because AMI has been deployed for almost all customers. Customer accounting and customer service expense are based on historical expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

V. ALLOCATION OF THE FUNCTIONALIZED REVENUE REQUIREMENT

Q. How is the Company proposing to allocate the functionalized revenue requirement across classes of customers in this proceeding?

A. The Company is allocating the functionalized revenue requirement to classes consistent with the Commission's Direct Access Rules. These rules indicate that "rates for any class of consumer must be based on the unbundled costs to serve that class."[5] In this filing, the Company has allocated the revenue requirement to each rate schedule based on the results of the functionalized class cost of service study. The proposed rates for each rate schedule included in the cost of service study are targeted to collect the cost of service for that rate schedule in the test period. Therefore, the proposed base rates for each class are based on the unbundled costs to serve that class.

Q. Do you have an exhibit that summarizes the functionalized results of the cost of service study?

A. Yes. Pages 1 and 2 of Exhibit PAC/1409 summarize the functionalized results of the cost of service study in column (4). This summary is provided at the level used to design rates. The cost of service for each rate schedule has been summarized into the following components: Transmission & Ancillary Services, System Usage, Distribution, Generation Energy Other Non-net Power Costs (Non-NPC), and Generation Energy NPC.

Q. What is the purpose of including this summary of cost components for the target functionalized revenue requirement?

A. The summary level for revenue requirement shown on pages 1 and 2 of Exhibit PAC/1409 summarize the cost of service results into the target revenue requirement components used in rate design.

The process of unbundling the Company's proposed prices is consistent with the method the Company first implemented in docket UE 116. For each rate

[4] OAR 860-038-0240(3)(b).

schedule, the functionalized costs are applied to rates as follows: distribution, billing, metering, and customer costs are included in each proposed delivery service schedule's Distribution rates; the FERC regulated transmission and ancillary services are included in each proposed delivery service schedule's Transmission & Ancillary Services rates; NPC generation costs are included in Schedule 200, Base Supply Service rates; and NPC are included in Schedule 201, Net Power Costs, Cost-Based Supply Service rates.

Q. Please explain the System Usage costs shown in exhibit PAC/1409 and how those costs are proposed to be recovered in rates.

A. In Order 12-500, the Commission directed the Company to develop a volumetric rate element for franchise fees that could be avoided by customers taking direct access. The amounts shown as System Usage costs in Exhibit PAC/1409 are a portion of the Oregon Franchise Tax and Oregon Energy Supplier Assessment from FERC Account 408 in the results of operations.[6] The System Usage costs have been calculated as the portion of the franchise and energy supplier taxes associated with revenues not paid by direct access customers: NPC and transmission and ancillary services. As discussed later, a separate volumetric rate element has been developed to recover these costs, which will not be paid by direct access customers.

[5] The Oregon Energy Supplier Assessment is a fee paid to the Oregon Department of Energy under ORS 469.421(8). While this treatment for this assessment was not reflected in Order 12-500, the Company has included it in the System Usage Charge because it is assessed in the same manner (a percent of revenue) as franchise taxes in FERC Account 408. The Company is therefore proposing parallel treatment.

Q. Have any adjustments been made to the functionalized revenue requirement by rate schedule resulting from the cost of service study?

A. Yes. The Company has made two adjustments to the functionalized revenue requirement. Consistent with past cases, the functionalized revenue requirement has been adjusted to remove the proposed changes to NPC collected through Schedule 201. Changes to Schedule 201 are implemented through the TAM, which is a separate proceeding from this general rate case, and the Schedule 201 changes will be addressed in that proceeding. The Company also made a balancing adjustment to reflect the difference in the interclass allocation between excess deferred income taxes and the net book value of the undepreciated equipment that has been replaced as a result of repowering. The Company committed to this adjustment in the stipulation to the 2019 Renewable Adjustment Clause (RAC). [7] The modified cost of service results reflecting these adjustments that remove the NPC increase from the functionalized revenue requirement and the balancing adjustment from the 2019 RAC settlement is shown on pages 1 and 2 of Exhibit PAC/1409. This exhibit displays the target functionalized revenue requirement used in the design of rates proposed in this general rate case.

Q. Do the Company's proposed rates collect the target functionalized revenues?

A. Yes. The revenues calculated by multiplying the test period billing determinants by the proposed rates are summarized in column (7) on pages 1 and 2 of Exhibit PAC/1409. A direct comparison to the target functionalized revenues shown in column (6) of this exhibit shows that the calculated revenues equal the target revenues

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[6] *See In the matter of PacifiCorp dba Pacific Power's 2019 Renewable Adjustment Clause*, Docket No. UE 352, Order No. 19-304 at Appendix A at 4-5 (Sept. 16, 2019).

with the exception of small differences due to the rounding of rates. The detailed calculation of proposed revenues based on billing determinants and proposed rates is shown on pages 3 through 12 of Exhibit PAC/1409. Revenue from Schedule 80 - Generation Investment Adjustment, Schedule 196 - Adjustment to Remove Deer Creek Mine Investment From Rate Base, and Schedule 202 - Renewable Adjustment Clause Supply Service Adjustment were set to zero in proposed rates, since the costs being recovered through these adjustments will be incorporated into base rates. Proposed tariff changes presented in Exhibit PAC/1401 include the cancellation of these schedules.

Q. Have you prepared an exhibit showing the estimated effects of the prices proposed in this general rate case?

A. Yes. Exhibit PAC/1410 shows the estimated effect of the Company's proposed prices. It contains two summary tables. Table 1410-1 shows the effect of the proposed prices by delivery service rate schedule for the proposed net rate increase on January 1, 2021, of $70.8 million which includes the requested revenue requirement change of $78.0 million less the requested Federal Tax Act Adjustment credit of $24.9 million plus the requested Generation Plant Removal Adjustment of $17.3 million plus the impact of the $0.4 million RMA rebalancing (discussed later in my testimony). Table 1410-2 shows the effect of the proposed changes by delivery service rate schedule incorporating the estimated effect of rate changes in 2020 for outstanding RAC filings.[8] The outstanding RAC filings are currently estimated to

[8] *See In the matter of PacifiCorp dba Pacific Power's 2019 Renewable Adjustment Clause*, Docket No. UE 352, Order No. 19-304 (Sept. 16, 2019); *In the matter of PacifiCorp dba Pacific Power's 2020 Renewable Adjustment Clause*, Docket No. UE 369, Stipulation and Joint Testimony (Jan. 31, 2020).

increase revenue by $9.5 million in 2020. The estimated increase for outstanding RAC filings, shown in column (7) of Table 1410-2, reduces the net increase that will go into effect on January 1, 2021, from $70.8 million to $61.3 million. These tables show the effect of the price changes on both base revenues and net revenues. Base revenues show the effect before the impacts of any adjustment tariffs. Net revenues include the effect of adjustment tariffs (discussed directly below) and the RMA.

The adder columns in Tables 1410-1 and 1410-2 show revenues from adjustment tariff schedules (Schedules 95, 104, 203 204, 207, 299, proposed 195 and proposed 197). The adder revenue is added to base revenue to calculate net revenue including adjustment schedules. Table 1410-3 shows the calculation of the adjustment revenue included in the adder columns in Tables 1410-1 and 1410-2. Table 1410-4 shows the present and proposed rates for these adjustment schedules. These tables exclude the effects of pass-through adjustment schedules for Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Beginning on page 5 of Exhibit PAC/1410 are the monthly billing comparisons for each of the major delivery service rate schedules showing the customer bill impacts of the proposed prices at various levels of usage. The monthly billing comparisons in Exhibit PAC/1410 show the expected rate increases for January 1, 2021, from proposed rates. The monthly billing comparisons also include the effects of all adjustment schedules, including estimated RAC changes in 2020 and the pass-through adjustment schedules listed above.

Q. What are the Company's rate spread objectives in this case?

A. The Company's rate spread objectives in this case are to minimize price impacts on our customers while fairly reflecting cost of service and sending proper signals about increasing costs.

Q. What is the Company's rate spread proposal in this case?

A. Based on the cost of service results and in order to achieve the Company's rate spread objectives in this case, Table 2 below summarizes the Company's proposed net percentage price changes for the major rate schedule classes.

TABLE 2

Residential Schedule 4	**5.0%**
General Service	
Schedule 23/723 (0-30kW)	**5.8%**
Schedule 28/728 (31-200kW)	**4.0%**
Schedule 30/730 (201-999kW)	**4.1%**
Large General Service Schedules 47/747, 48/748 (≥1,000kW)	**8.6%**
Agricultural Pumping Service Schedule 41/741	**10.0%**
Lighting Schedules	**-18.9%**
Overall	**5.4%**

Under the Company's proposal, the rate change that takes effect January 1, 2021, will result in no customer rate schedule class receiving an increase greater than 10.0 percent. The Company's proposed rate spread strikes a balance between moderating rate impacts on customers, while sending proper price signals about increasing costs and minimizing subsidization across rate schedule classes. As a result, the Company proposes revisions to the RMA to achieve these goals.

Q. Please describe the RMA.

A. The RMA, Schedule 299, is designed to mitigate the impacts of changes in the functionalized revenue requirement on net rates across rate schedules. Net rates are the rates that customers pay once all tariff riders (including the RMA) are taken into account. The RMA is designed to be revenue neutral overall at the time a general rate case price change is implemented, resulting in RMA credits for some rate schedule classes requiring rate mitigation with offsetting RMA charges for others. The RMA was first implemented in docket UE 116 to transition to cost of service rates under Senate Bill (SB) 1149. The Schedule 299 RMA tariff rider is included in customers' rates for delivery services in order to minimize the effect of the price change allocation across customer classes.

Q. Besides mitigation of rate changes across rate schedules, what other factors contribute to the adjustment of the RMA in a general rate case?

A. In each general rate case, the RMA must be rebalanced in order to achieve revenue neutrality so that the revenues from the RMA charges and the RMA credits are in balance. The present Schedule 299 RMA rates were designed to be revenue neutral in the calendar year 2014 test period from the Company's 2013 Rate Case; however, due to changes in rate schedule loads, present Schedule 299 RMA rates are not projected to produce revenue neutrality in the calendar year 2021 test period of this case. The present RMA rates result in RMA credits that exceed RMA charges by $0.4 million for the 2021 test period loads (see Exhibit PAC/1410, Table 1410-3, Column 11, Row 18). Consistent with previous RMA revisions, the proposed RMA rates have been designed to be revenue neutral for the 2021 test period. As a result of this realignment, the proposed net rate increase in this case is $0.4 million higher than the base revenue requirement increase (Exhibit PAC/1410, Table 1410-1 and Table 1410-2).

Q. Has the RMA required rebalancing in previous general rate cases?

A. Yes. For example, in the 2013 Rate Case the RMA required a rebalancing adjustment of $0.2 million.

Q. What are the present and proposed RMA revenues and rates in this case?

A. The present and proposed RMA revenues are shown in Exhibit PAC/1410, Table 1410-3, columns (11) and (12). Present and proposed RMA rates are shown in Exhibit PAC/1410, Table 1410-4, columns (11) through (16).

Q. What is the Company's RMA objective in this case?

A. The Company's RMA objective in this case is to minimize rate schedule subsidization through the RMA while minimizing impacts on customers. As a result, the Company has limited RMA charges and credits as much as possible. The Company proposes decreases to present RMA credit rates. The Company is proposing to reduce the RMA credit to Schedule 41/741. Reducing this credit still allows the Company to cap the increase for Schedule 41/741 at 10 percent which is just under twice the overall proposed net percentage increase of 5.4 percent.

For Large General Service Schedules 47/747 and 48/748, the Company proposes to reduce the present RMA credit rates to half of their current level in order to minimize cross-subsidization. The proposed January 1 net increase for Schedules 47/747 and 48/748 is 8.6 percent. With this proposal, Schedule 47/747 and 48/748 will continue to receive significant RMA credits equal to $5.4 million in annual credits to these rate schedules. Nonetheless, the Company believes the proposed RMA credits for Schedule 47/747 and 48/748 are reasonable in light of the overall percentage increase proposed for these customers.

The Company proposes bringing the RMA to zero for Residential Schedule 4, General Service Schedule 23/723, and for Lighting Schedules 15, 51, 53 and 54. For General Service Schedules 28/728, and 30/730, the Company proposes setting their RMA surcharges to levels that produce a net increase slightly less than the overall average at about 4 percent.

Overall, the Company believes that these proposals result in just and reasonable rates and will minimize rate impacts while reducing subsidization through the RMA.

VI. SCHEDULE 195 - FEDERAL TAX ACT ADJUSTMENT

Q. What rates does the Company propose for Schedule 195 - Federal Tax Act Adjustment?

A. As discussed in Ms. McCoy's testimony, the Company proposes refunding to customers $24.9 million annually for the next three years to pass back the remaining balance at the end of 2020 for the current tax benefit as well as the remaining balance for excess deferred income taxes. Page 5 of Exhibit PAC/1410 shows the calculation of proposed rate spread and prices for Schedule 195 - Federal Tax Act Adjustment. Consistent with how rates were first set in Schedule 195, the Company proposes spreading the credit to classes on the basis of base revenue less NPC. The Proposed Adder columns in Tables 1410-1 and 1410-2 in Exhibit PAC/1410 include the impact of the proposed Federal Tax Act Adjustment.

VII. SCHEDULE 197 - GENERATION PLANT REMOVAL ADJUSTMENT

Q. How does the Company propose recovering costs associated with closure of Cholla Unit 4?

A. The Company proposes that the costs associated with Cholla Unit 4 be recovered through a new adjustment, Schedule 197 - Generation Plant Removal Adjustment. In the draft Schedule 197, the Company proposes collecting $17.3 million annually from customers starting on January 1, 2021, through April 2025. The $17.3 million includes the costs associated with undepreciated plant, materials and supplies, construction work in progress and liquidated damages associated with the closure of Cholla Unit 4 as discussed in Ms. McCoy's testimony. Page 6 of Exhibit PAC/1410 shows the calculation of proposed rate spread and prices for Schedule 197. The Company proposes spreading the surcharge to classes on the basis of base generation revenue requirement. The Proposed Adder columns in Tables 1410-1 and 1410-2 in Exhibit PAC/1410 include the impact of the proposed Generation Plant Removal Adjustment.

VIII. RATE DESIGN

Q. Please generally describe the process for designing rates to collect the proposed revenue requirement.

A. Proposed rates are designed to collect the target functionalized revenue requirement based on customer billing determinants including number of monthly bills, kW, and kWh consumed for the rate case test period. The billing determinants used in this case reflect the forecast test period for the 12 months ending December 2021.

Q. How are the forecast billing determinants developed?

A. Forecast test period billing determinants are developed based on the Company's forecast test period bills and energy forecasts along with the historical test period billing determinants.

A three-step process occurs in developing test period billing determinants. First, the Company forecasts monthly test period bills and energy by class and by rate schedule which is supported in the testimony of Mr. Rick T. Link.

Second, a full set of billing determinants, including all rate elements such as kW demand, load size, reactive power quantities and kWh by rate block, are retrieved at the customer invoice level from the Company's billing system for the base period—in this case, the 12 months ended June 2019. These historical billing determinants are summarized by class, rate schedule, and voltage level.

Finally, a full set of forecast billing determinants is developed using the historical base period data and the test period forecast. The forecast billing determinants are calculated based upon the ratio of historical bills and energy (temperature normalized) in the base period to the forecast bills and energy provided in the sales forecast.

Q. Have you provided an exhibit showing proposed rates and the billing determinants used to design rates?

A. Yes. Pages 3 through 13 of Exhibit PAC/1409 contain historical and forecast billing determinants along with present and proposed base rates.

Q. What underlying themes guide the rate design proposals that you are making in this rate case?

A. There are three major underlying themes to the rate design proposals that I make: making energy more affordable, adapting to a more sustainable future, and giving customers choices.

Q. How do your rate design proposals in this case make energy more affordable?

A. Making energy more affordable means designing rates in ways that make energy consumption less expensive for customers. My testimony proposes several ways to achieve this goal. Improving and expanding time varying rates gives customers more opportunities to save when they consume energy during times when energy is less expensive. Unwinding rate structures with tiered energy charges will make the cost of energy more equitable across different customer usage levels and minimize the impacts of the Company's current tiered rates which for the residential class can be particularly harmful to low-income customers.

Well-designed prices should send a clear price signal to customers about the incremental cost of additional energy consumption and thus promote energy efficiency. However, when rate structures unduly penalize incremental energy usage above its additional cost, it can result in unintended consequences. For example, inverted block tiered energy pricing discourages electric vehicle adoption and encourages the expansion of natural gas service.

Q. What does it mean for rate designs to adapt to a more sustainable future?

A. In the context of rate design, adapting to a more sustainable future means creating opportunities for the Company's rates to encourage customer behavior that mitigates impacts to the environment. Signaling customers to shift energy use to times when renewables are more prevalent on the grid and removing disincentives to electrification are important ways that this can be accomplished.

Q. How do your rate design proposals give customers choices?

A. Giving customers choices means providing more than one option for how a customer will be charged for the services they receive from the utility. When customers have different options, this creates possibilities for bill savings, utility cost reductions, and the ability to use electricity in new and beneficial ways. For this rate case, the Company is proposing two new time of use pilot programs and making one existing time of use pilot more broadly available. The Company is also proposing a real-time pricing pilot and an interruptible tariff pilot for its larger customers.

Q. Please summarize the rate design changes proposed by the Company.

A. The basic structure of the Company's current tariffs, broken out into Delivery Service and Supply Service tariffs as first approved in docket UE 116, is proposed to remain in effect. In this rate case, I will propose rate design changes that will affect the underlying structure for how Schedule 201 rates are set. The prices for Schedule 201 themselves will be proposed in the Company's 2021 TAM, a separate proceeding from this rate case.

In this case the Company is proposing splitting the basic charge for residential customers into different prices based on dwelling type with a proposed increase in the basic charge for customers living in single-family homes and a proposed decrease for customers living in multi-family homes. The Company is also proposing to reduce by half the difference in the first and second tier energy charges.

For large non-residential customers, the Company proposes modernizing its time of use periods and increasing the differential between on- and off-peak energy. Several innovative time varying rate options are proposed for this case including a new residential time of use pilot, a non-residential time of use pilot, a permanent agricultural pumping time of use option, and an interruptible service pilot and real-time day-ahead pricing pilot for larger customers.

Residential Rate Design

Q. Please explain the proposed tariffs for residential customers.

A. Residential customers are served on Delivery Service Schedule 4. The Company proposes splitting the Basic Charge into two separate charges for customers living in single-family and multi-family dwellings. The Company proposes increasing the basic charge from its current level of $9.50 per month to $12 for single-family dwellings and decreasing it to $7 for multi-family dwellings. This change betters reflects the fixed costs of serving residential customers and more accurately recovers costs from customers who live in multi-family dwellings and have a lower cost of service. The Company also proposes to decrease the differential between its two inclining tier block energy charges for residential by 50 percent.

For residential customers, as well as for all classes of customers, Schedule 200, Base Supply Service, is proposed to reflect changes in the non-NPC generation revenue requirement as indicated in pages 1 and 2 of Exhibit PAC/1409. The portfolio options (Schedules 210 through 213) do not require changes since they are adders to customers' Schedule 201 rates.

Q. Why is the Company proposing an increase in its basic charge for most residential customers?

A. The Company's marginal cost of service study which I present as Exhibit PAC/1408 shows on Table 3 that the annual marginal cost of billing- and commitment-related cost is $357.13 or about $29.76 per month. At $9.50, the Company's present basic charge falls far short of cost. Making movement towards a cost-based basic charge is important, because this helps the Company keep energy more affordable for its customers. Given a fixed level of revenue to be collected from all residential customers, an increase in the basic charge will lower energy charges.

Q. Why is the Company proposing a separate basic charge for multi-family customers?

A. The Company is conscious of the effects changing rates can have on its customers. While economically justified and based upon sound cost causation principles, raising the basic charge and decreasing the tiered rate differential increases the cost of electricity for the smallest users. Customers who live in multi-family dwellings like apartments or condos tend to use much less energy than customers living in single-family homes. The Company also recognizes that the fixed costs of serving customers in multi-family configurations can be lower than for single-family homes. To mitigate rate impacts on smaller users while simultaneously better aligning its rates with cost causation, the Company proposes charging different basic charges for residential customers dwelling in multi-family versus single-family dwellings.

Q. What is the basis for a multi-family basic charge that is nearly half of the basic charge for single-family customers?

A. In its Marginal Cost Study, the Company specifically calculates marginal commitment costs for meters, service drops, line transformers, poles and conductors, and also calculates the marginal cost of billing and collections, uncollectibles, and customer service. Marginal commitment-related transformer costs are largely driven by the number of customers on average who utilize a shared transformer. On average for the entire residential class, 3.95 customers are served from a transformer. This value is significantly different for multi-family and single-family customers. On average, 2.92 single-family residential customers are served by a transformer compared to 8.49 multi-family customers per transformer. In general, customers who dwell in multi-family buildings live in more dense habitations and there are economies of scale related to the cost of stepping down voltages to a level they can use relative to single-family where more equipment must be installed to serve a less dense population.

A key driver for the marginal commitment costs of poles and conductor is the distance between customers and the distribution substation that serves them. This marginal cost is higher for customers who are served in more remote outlying areas where longer spans of conductor and more poles must be installed to provide service. A greater proportion of multi-family customers are close by to the substation that serves them than for single-family customers.

The Company prepared an analysis of the marginal commitment and customer costs examining specifically how they differ between single-family and multi-family customers for the costs of transformers and poles and conductor. Exhibit PAC/1411 shows the results of this analysis which calculates that the marginal commitment and customer costs for a multi-family residential customer is $18.62 per month, or about 57 percent of the same value for single-family residential customers of $32.81. Making a 10 percent movement from the current basic charge of $9.50 to the $32.73 marginal cost level calculated for single-family results in a level of $11.83 which the Company rounded to $12 for its proposed single-family basic charge. Applying the 57 percent difference in marginal cost resulted in a value of $6.71 for multi-family that was rounded to $7 for its proposed multi-family basic charge.

Q. How does the Company's current and proposed basic charge compare to other utilities in Oregon?

A. The Company's current and proposed basic charge compare very favorably to the basic charges of other Oregon electric utilities. The Company examined the residential rates of 15 other utilities which includes the other two investor owned utilities (IOUs) in the state and 13 publicly owned electric utilities with service territory in close proximity to the Company's. Table 3 below shows those basic charges as well as an average for all 15 utilities.

Table 3. Comparison of PacifiCorp's Current and Proposed Basic Charge to Other Oregon Electric Utilities

Utility	Residential Basic Charge
Current Pacific Power	$9.50
Proposed Pacific Power	$7 multi-family/$12 single family
Portland General Electric	$11.00
Idaho Power	$8.00
Central Electric Coop	$19.38
Central Lincoln PUD	$24.00
City of Ashland	$14.00
City of Hermiston	$16.00
City of Monmouth	$10.31
Coos-Curry Electric Coop	$26.94
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	$14.00
Tillamook PUD	$23.10
Umatilla Electric Coop	$18.00
Average	$18.62

Note - Prices were those available from each utility's website as of December 17, 2019

The average basic charge of all 15 utilities examined is $18.62 which is well above the Company's proposed basic charge of $7 for multi-family and $12 for single-family.

Q. Distinguishing between residential customers who dwell in single- and multi-family homes is a new feature for the Company's tariffs. How will this difference be defined for different basic charges on Schedule 4 – Residential Service?

A. The Company's proposed definition of a multi-family home will be the same as defined in its Electric Service Requirements Manual (ESR), which is a resource that clarifies electric service requirements for the Company's customers prior to and during construction. The ESR defines a multi-family dwelling as "a building that contains three or more dwelling units".[9] On tariff Rule 4 - Definitions, multi-family home will be defined in this way and a single-family dwelling will be defined as any other building.

Q. How are residential energy charges currently structured?

A. Residential energy charges use what is called an inclining block or tiered rate structure where energy usage up to a specific threshold per month receives a lower price and successive energy consumption is priced at a higher rate. Presently, the first 1,000 kWh[10] in a month are 10.012 cents per kWh and all additional kWh are 11.985 cents per kWh.

Q. Are residential customers of the other IOUs in Oregon subject to inclining block energy charges?

A. Yes. Both Portland General Electric Company (Portland General Electric) and Idaho Power Company's (Idaho Power) residential customers are subject to inclining block energy charges. The percentage differentials between tiers, however, for the other two IOUs are smaller, both in absolute cents per kWh and percentage, than for the Company. Table 4 below shows current residential energy prices for all three utilities:

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[8] *See* PacifiCorp's Electric Service Requirements Manual (4th Ed) at vi, *available at* https://www.pacificpower.net/working-with-us/builders-contractors/electric-service-requirements.html.

[9] 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.

Table 4. Comparison of Tiered Residential Rates for IOUs in Oregon[11]

Utility	1st block price (¢/kWh)	2nd block price (¢/kWh)	Different between 1st and 2nd block	% Difference
PacifiCorp	10.012	11.985	1.973	20%
Portland General Electric	11.234	11.956	0.722	6%
Idaho Power	8.4823	10.0018	1.5195	18%

At a 20 percent difference between tiers, the Company's tiered structure is more steeply inclined than its peers with a six percent difference in the first and second tier for Portland General Electric and an 18 percent difference for Idaho Power.

Q. What are the potential benefits of an inclining block structure?

A. The inclining block rate structure is often referred to as an effective tool for encouraging customers to save energy. The theory is that the first block covers some basic level of usage at a lower rate to help keep the overall bill affordable for customers and a second and possibly third block with a higher rate makes incremental energy usage more expensive. For a customer with usage in the higher tiers, making energy efficient choices like installing a heat pump water heater will yield greater savings than would have been achieved under a flat energy charge rate design. Inclining blocks are also sometimes considered more progressive with low income users, who theoretically have lower usage, paying a lower average price.

[10] Prices for Portland General Electric and Idaho Power were those that were available online on December 12, 2019, from their residential schedule's tariff.

Q. Is the inclining block structure still an appropriate rate design for residential customers?

A. No, not in light of changes in the electric industry and the likelihood of further evolution in the energy landscape of the future. While well intentioned, tiered rates can result in unintended consequences, particularly as the electric industry evolves. Tiered rates are unfair, are not economically justified, and create perverse incentives. In addition, tiered rate structures can be a source of confusion for residential customers.

Q. How are tiered rates unfair?

A. Charging higher prices for greater usage in a given month arbitrarily creates winners and losers. Customers who heat their home with natural gas or a woodstove are winners and those who choose to heat their home with electricity or otherwise do not have access to gas are losers. A bustling, multi-generational household with a large number of people living under one roof is a loser and the person living alone in an apartment is a winner. A customer who chooses to buy an electric vehicle and charge it from home is a loser and another customer who keeps their internal combustion engine vehicle is a winner. Effectively, inclining block rates unfairly reward some customers and punish others, often for reasons outside the customer's control or in ways that incentivize behaviors that are at odds with changes in energy policy.

Q. Please describe why tiered rates are not economically justified.

A. There is no reason why after using 1,000 kWh in a given month that the next kWh consumed by a customer should cost more. The timing of energy consumption, both seasonally and during different hours, can affect the utility's cost of providing kWh to the customer. The load factor, or the effective utilization of kWh consumption relative to peak kW demand, can also change the average cost of providing energy. However, there is nothing special about additional overall usage in a monthly billing period that makes it more expensive for the utility to produce that next kWh of electricity.

Q. How do tiered rates create perverse incentives?

A. Relative to a flat energy charge rate structure, inclining block prices encourage customers to switch fuels to natural gas. Avista Corporation, Cascade Natural Gas Corporation, and Northwest Natural, Oregon's three natural gas providers, do not use an inclining block rate structure for residential customers for volumetric gas consumption. In other words, the price for each therm that a natural gas customer in Oregon purchases is flat and does not become more expensive with greater usage within a monthly billing period. As the result of its rate structure, PacifiCorp has a competitive disadvantage to serving residential customers with electricity to heat their homes relative to natural gas.

Another unfavorable result of tiered rates is that they make residential transportation electrification less attractive. While a customer can at this time still experience "fuel" savings with charging their electric vehicle at the higher second tier price relative to purchasing gasoline, as more costs get pushed into the customer's incremental cost of energy on the second tier the economic rationale to choose an electric car is weakened.

Q. Do tiered rates help low income customers by making a modest level of usage tied to a customer's basic needs more affordable?

A. Not necessarily. It is true that overall average monthly usage tends to increase with income, but it is also true that a significantly smaller percentage of PacifiCorp's lower income customers use less than 1,000 kWh a month on average. In 2017, the Company conducted an email survey of its customers and collected end use and demographic information from participants. Table 5 below highlights some of the Company's findings regarding energy usage and income:

Table 5. Usage Characteristics and Household Income from PacifiCorp's 2017 Residential Customer Survey

	Income Level		
Average Monthly Usage Level	**Below $50,000**	**$50,000 to $74,999[1]**	**$75,000 and greater**
0 - 1,000 kWh	41%	61%	62%
1001 - 1,500 kWh	46%	25%	27%
1,501 kWh and over	13%	14%	11%
Average Monthly Usage (kWh)	941	966	990
	Income Level		
	Below $50,000	**$50,000 to $74,999[1]**	**$75,000 and greater**
Natural Gas Used as Main Fuel for Heating	30%	44%	56%
Sample Size	6,889	3,723	6,316

[1] Note - $60,212 was the median household income in Oregon in 2017 per https://www.deptofnumbers.com/income/oregon/

According to the Company's survey results, about 41 percent of customers with household incomes less than $50,000 per year have average monthly usage less than 1,000 kWh a month. In contrast, 62 percent of higher income households making more than $75,000 per year have monthly usage less than 1,000 kWh. The survey results also notably show that lower income households are much less likely to use natural gas as their main fuel for heating. Customers who heat their homes with electricity will have a much harder time staying warm and keeping kWh consumption in the winter below the 1,000 kWh monthly threshold compared to customers who use gas. Table 5 shows that only 30 percent of PacifiCorp households making less than $50,000 per year use natural gas as their main fuel for heating. In contrast, customers making $75,000 and greater are nearly twice as likely to use gas with 56 percent reporting that they use natural gas as their main fuel to heat their homes. The tiered rate structure makes energy bills less affordable for many lower income customers, particularly when they use electricity to heat their home. The average monthly usage for survey respondents making less than $50,000 per year who do not use natural gas as their primary heating fuel during the peak heating season in the billing months of December, January and February, was 1,563 kWh—well above the 1,000 kWh first tier threshold.

Q. Is the tiered rate structure universally understood by customers?

A. No. According to the Company's 2017 survey, only 48 percent of customers were aware of the tiered rate structure. Of those 48 percent who were aware of the structure, 44 percent said that it did not impact their electricity usage decisions.

Q. What prices does the Company propose for residential energy charges?

A. The Company's proposal for residential energy charges in this case balances the need to effect change gradually while also striving to modernize the Company's rate design to be consistent with policy-driven[12] changing demands on the electricity sector, including increased electrification through electric vehicle charging and a desire to decrease energy sector emissions. Thus, while the inclining block rate structure is

[11] For example, SB 1547, which among other things made a finding that "(w)idespread transportation electrification requires that electric companies increase access to the use of electricity as a transportation fuel in low and moderate income communities."

problematic, I propose reducing the differential between the price on the first tier and the second tier as a reasonable and gradual change that is in the interest of PacifiCorp's customers.

To mitigate customer impacts, the Company recommends energy prices that reduce the differential between tiers by 50 percent. The Company therefore proposes a price of 10.210 cents for the first 1,000 kWh in a month and 11.210 cents per kWh for all additional kWh.[13] The Company recommends that this change would occur for all base tiered rate components that make-up residential energy charges which include rates set in the TAM (Schedule 201).

Q. Why are more affordable energy costs desirable?

A. The energy charge sends an important and powerful price signal to customers about the cost of their consumption. Motivated by bill savings, customers may modify their behavior, adopt conservation measures, and choose to live in more efficient homes. Along with demand-side management incentives and rebates, the price of energy that all customers face is an important tool for limiting overall customer usage.

Conservation, however, is not the only behavior that is motivated by the price signal that energy charges present. Customers can often save on their monthly energy costs by connecting to natural gas service and switching the fuel of end uses like space heating, water heating, and cooking from electricity to natural gas. All else equal, higher incremental energy charges provide a greater motivation for fuel switching. Over the past recent decades, the proportion of households that use natural gas as their primary heating source has steadily risen in Oregon. Figure 1 below

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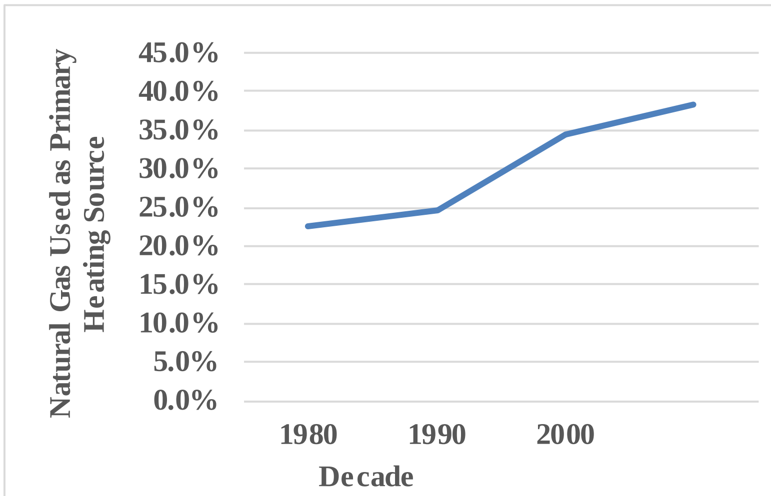
[12] Proposed prices include changes proposed in this case and the concurrent TAM proceeding.

shows how the share of households in Oregon that heat their home with natural gas has grown since 1980:

Figure 1 – Natural Gas Penetration in Oregon from U.S. Census Bureau Information



Source: United States Census Bureau website https://www.census.gov/hhes/www/housing/census/historic/fuels.html and https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=CF

The overall magnitude of energy charges are also a very important consideration for transportation electrification. In general, a customer's economic decision to adopt an electric vehicle will be influenced by the price of energy. Lower energy prices provide a greater incentive to switch from an internal combustion engine car to an electric vehicle.

The current pricing regime of steeply tiered energy charges penalizes incremental consumption in a month, while the Company's proposal provides greater balance of the interests of conservation with the need for a more modern rate design that accommodates current and future energy policy. At the Company's proposed energy charges of about 10.2 cents per kWh for the first tier and 11.2 cents for the second tier, that balance will be supported and customers will continue to have good reason to minimize their energy usage while also not dis-incentivizing transportation electrification or unfairly encouraging fuel switching to natural gas.

Residential Time of Use Pilot

Q. Please describe the Company's proposed residential time of use pilot.

A. The Company proposes creating a new time of use residential rate pilot, Schedule 6. Under Schedule 6, residential customers would pay 17.917 cents per kWh during the on-peak period of 3:00 p.m. to 9:00 p.m. during the summer months of July through September, and 6:00 a.m. to 8:00 a.m. and 5:00 p.m. to 11:00 p.m. in the non-summer months of October through June. During all other times considered off-peak, they would pay 6.633 cents per kWh. Schedule 6 would be available for up to 5,000 customers on a first-come, first-served basis.

Q. Why is the Company proposing a residential time of use pilot at this time?

A. Providing residential customers with a time of use rate option that can provide them with a meaningful savings opportunity is consistent with the goals of making energy more affordable, adapting to a more sustainable future, and giving customers choices. The Company already offers a time of use rate option for small customers (Schedule 210) that was implemented as part of SB 1149. Participation in this option has been very limited, however, with only 1,039 customers participating. The potential for residential customers to save on Schedule 210 is relatively small with the average residential customer saving only $1.22 per month. Presently, the relative differential between on- and off-peak prices is 1.6. Limiting participation to a modestly sized pilot allows the Company to gain experience with a more potentially beneficial time of use option without significant risk or cost for its customers. Time varying rates can be an important way to manage load on the grid, shift load to times when renewables are more abundant, and responsibly encourage transportation electrification. This pilot would provide an opportunity for customers to lower their bills based on their own energy usage habits while providing the Company with useful data on customer behavior.

Q. Why isn't the Company simply proposing to adapt its existing time of use offering?

A. The pilot time of use option that the Company is proposing has significant differences with the existing residential option on Schedule 210 including a higher on-/off-peak differential, different time of use periods and a flat rate structure. Before modifying the existing time of use offering, the Company wants to test Schedule 6 and gain a better understanding of customer experience and behavior. As the Company gathers data, the Company can evaluate the design merits of Schedule 6 and understand any potential customer impacts from transitioning Schedule 210 customers.

Q. How did the Company select on- and off-peak time periods for proposed Schedule 6?

A. To develop its proposed time of use periods, the Company used a three year[14] average of Energy Imbalance Market (EIM) data consistent with the Commission's direction in the Resource Value of Solar (RVOS) proceeding.[15]

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[13] Specifically, the Company used the three-year period ending on October 31, 2019.
[14] *See In the matter of PacifiCorp dba Pacific Power Resource Value of Solar,* Docket No. UM 1910, Order No. 19-021 at 9 (Jan. 1, 2019).

Prices were examined during two seasons – summer, which includes July through September, the three months where the average energy cost is at its highest, and non-summer, which includes October through June. Examining a matrix of average real-time EIM prices shown on Page 1 of Exhibit PAC/1412, the Company ranked the hours in both the summer and non-summer months. The highest six hours were selected as on-peak for the summer months and the highest eight hours were selected for the non-summer months yielding the Company's proposed periods. Six hours were chosen for summer to balance the need of capturing a sufficient level of high cost hours to have a meaningful difference in value with the potential impacts to participants who will likely need to adapt their behavior to save money on the rate option. Eight hours were used for the non-summer months to capture the higher value periods in both the morning and the evening. Holidays and weekends were not considered as off-peak because the average value was not substantially different than non-holidays or weekdays. Page 2 of Exhibit PAC/1412 shows the ranking of prices by season and hour.

Q. What on-/off-peak differential in energy price does the Company propose for Schedule 6?

A. The savings that customers have been able to achieve on the Company's existing residential time of use offering has not yielded high levels of adoption. The Company's proposed pilot will test whether achieving stronger participation requires a greater differential in the on- to off-peak prices which will give customers a greater opportunity to save from shifting load. In the Company's Idaho service territory, the Company has a very successful time of use option that has an 18 percent participation rate. The energy charges on Idaho Schedule 36 – Optional Time of Day Residential Service do not have tiers and have a 2.7 ratio on average between on- and off-peak pricing. For the purposes of developing a robust pilot offering, the Company proposes that a 2.7 differential be applied to proposed rates for Schedule 6.

Q. Please describe how the Company calculated rates for proposed Schedule 6.

A. Exhibit PAC/1413 shows the calculation of proposed Schedule 6 prices. Energy prices were calculated by first determining the average proposed energy price for residential Schedule 4. The estimated units of on- and off-peak energy were taken from energy usage in both periods from the Company's load research study for the residential class. The average energy price was then adjusted so that the on- and off-peak prices would be revenue neutral and produce the same level of revenue as energy charges for the whole class, but still have a relative differential of 2.7 as previously discussed. To incorporate the prices for Schedule 6 into the Company's unbundled rate structure, the Company recommends that base delivery and supply charges be set to the average price proposed for Schedule 4 with the entire time varying differential included in Schedule 201 as an on-peak charge of 7.050 and an off-peak credit of 4.234. Both of these prices applied to the average residential profile yield the average Schedule 201 price. Final prices for Schedule 201 will be set in the TAM proceeding.

Q. Why is the Company proposing that the entire time varying differential be included in Schedule 201?

A. Schedule 201 recovers the Company's NPC, which are the variable short-run costs associated with supplying its customers with energy. When a customer adopts a time varying rate option and shifts its load away from high cost times to low cost times, the most immediate benefit is realized in the Company's NPC. While customer behavior may have additional capacity benefits in the long run, those benefits are not immediately achieved and it is therefore sensible to include the full magnitude of time variance in the price in Schedule 201.

The Company also proposed using Schedule 201 to reflect on- and off-peak energy, because Schedule 201 is updated annually through the TAM whereas other base prices are typically only updated in general rate cases which the Company does not file as regularly, because it prudently manages its costs. Using Schedule 201 therefore ensures that the Company's fixed cost recovery is put less at risk and potential disincentives for the Company to promote Schedule 6 and see that customers are successful at shifting their energy to off-periods is removed. In the future, if the Company is able to scale up a larger, more mature time of use option that reaches a steady state, it would recommend spreading the on- and off-peak energy components to other rate categories.

Q. Why does proposed Schedule 6 not have tiered energy charges?

A. As discussed earlier in my testimony, the tiered rate structure, while used as a tool to promote conservation, can create a number of unintended consequences. Combining tiered pricing with time of use rates may also be more confusing for customers and harder for them to understand. Including a component that makes energy more costly as a customer uses more during a monthly billing period may confuse customers and distract from the message to them to manage their loads to avoid the on-peak period. Including both a time of use element and an inverted tier block element within the proposed pilot may also make it harder for a customers to evaluate whether to enroll. Additionally, the Company has concerns that combining tiers with time varying rates may make it more challenging to study the pilot rate option.

The primary message given through a time of use rate is for participants to use energy at times when energy costs are lower. This gives customers a price signal that appropriately mirrors the actual costs incurred to serve customers. Energy costs are affected by the time of the day, but are not affected by how much usage a customer has in a particular month. As discussed earlier in my testimony, the 1,001st kWh does not cost the Company more to serve. However, high usage during peak hours can impact the Company's costs, and eventually, the costs to customers.

Q. What other feature does the Company propose for Schedule 6?

A. Like Schedule 210, the Company proposes an annual guarantee payment for Schedule 6. If over the course of the customer's first year on time of use rates, the customer's total energy costs are greater than 10 percent over what costs would have been for the same period under standard Schedule 4 residential rates, the Company will make a guarantee payment to refund the difference in excess of 10 percent. The purpose of the guarantee payment is to limit participant risk and provide some assurance and protection that participants will not face a severely adverse annual billing impact from their decision to participate. Offering this guarantee payment under which customers will face no greater than a 10 percent increase in their annual energy cost for the first year will help the Company sign up customers for the pilot while still providing an incentive to participating customers to change their behavior.

Schedule 23/723 – Small General Service (less than 31 kW)

Q. Does the Company propose any changes for the structure of Schedule 23/723 - Small General Service rates?

A. No. For larger general service customers, the Company recommends eliminating or flattening declining block tiered rates, but it is not recommending the same thing for Schedule 23 at this time. Schedule 23 has a basic charge, two energy charges, and a load size charge and a demand charge that only applies to monthly usage in excess of 15 kW. Schedule 23 has two declining block energy charges where for secondary service the first 3,000 kWh is 10.047 cents and all additional kWh are 8.473 cents. The much higher first tier is helpful for recovering fixed costs because there is no demand charge for Schedule 23 customers who use less than 15 kW of demand. This higher volumetric rate ensures an appropriate level of cost recovery from smaller Schedule 23 customers who, before the Company deployed AMI, did not have meters capable of recording a demand register. The Company does not yet have a full 12 months of profile data from Schedule 23 customers from AMI and therefore does not have the data necessary to develop billing determinants for demand and load size charges for monthly kW usage less than 15. In a future case, when this data is available, the Company will consider a transition to a structure with demand and load size charges at all levels and flat energy charges. In this case, Schedule 23/723 rates have been modified to collect the target revenue requirement and to track functionalized costs.

Schedule 28/728 –General Service (between 31 and 200 kW)

Q. What does the Company propose for Schedule 28/728?

A. Schedule 28/728 rates have been modified to collect the target revenue requirement and to track functionalized costs. Presently, Schedule 28 has a declining block rate structure where for secondary service, the first 20,000 kWh are 6.941 cents and all additional kWh are 6.777 cents. Like inclining block tiered rates to which residential customers are subject, declining block tiered rates create additional complexity and send confusing price signals. The Company recommends eliminating tiers for this rate schedule and charging customers a flat price for energy.

Schedule 30/730 –General Service (between 201 and 1,000 kW)

Q. What does the Company propose for Schedule 30/730?

A. Schedule 30/730 rates have been modified to collect the target revenue requirement and to track functionalized costs. Presently, Schedule 30 has a declining block rate structure where for secondary service, the first 20,000 kWh are 6.118 cents and all additional kWh are 5.358 cents. Like Schedule 28, the Company recommends eliminating tiers for this rate schedule.

Schedule 41/741 – Agricultural Pumping Service

Q. What does the Company propose for Schedule 41/741?

A. Schedule 41/741 rates have been modified to collect the target revenue requirement and to track functionalized costs. Schedule 41 has a flat energy price in the summer and a declining kWh per kW structure during the winter months of December through March. For secondary service, summer energy usage is 9.587 cents per kWh and winter usage is 12.275 cents for the first 100 kWh per kW of demand and 9.587 cents for all additional kWh. To improve the transparency and simplicity of agricultural pumping service rates, the Company proposes eliminating the winter declining block kWh per kW block structure and having a flat year round energy price.

Q. Does the Company propose any other changes for Schedule 41/741?

A. Yes. Currently, the Company has a limited time of use pilot (Schedule 215) available for irrigators in the Klamath Basin that it has operated for several years. In this case, the Company proposes building off of the lessons learned from this pilot and establishing a permanent[16] time of use rate option that is available for all agricultural pumping customers.

Q. What lessons has PacifiCorp learned from its Schedule 215 pilot?

A. The Company learned that pumpers can be very successful at shifting their load from on-peak to off-peak times. During the historic test period of the year of the 12 months ending June 30, 2019, 96 percent of load for Schedule 215 pilot participants during the prime summer season was used during the off-peak period. This compares to 88 percent for the entire class of Schedule 41 agricultural pumping customers.

The average Schedule 215 customer saves about $747 per year, or about $21.01 per MWh, relative to what they would have on standard non-time varying Schedule 41 rates. The Company examined the difference in the value of energy between the on-peak period of 3:00 p.m. to 6:00 p.m., Monday through Friday, June through August, excluding Independence Day, and the off-peak period of all other

[15] Permanent here means that it is not a pilot with a cap on participation or a time limit over which it is available. All aspects of regulated utility prices and tariffs may change at any time subject to Commission approval. The Company anticipates that the on- to off-peak price differential as well as the time of use hours may need to evolve over time.

hours and determined that the estimated benefit of this shift in load is about $7.93 per MWh.

Finally, the Company learned that using a single on-peak window for time varying rates for agricultural pumping customers is not a scalable solution. Many of the Company's agricultural pumping customers are part of water projects where they draw water from a canal that is shared with other irrigators. If all of the irrigators on a given canal were to stop pumping during the same window of time, the water made available from the project would not be fully used.

Q. What does the Company propose for a permanent time of use option for agricultural pumping customers?

A. Taking the lessons learned from the Schedule 215 pilot, the Company proposes different design features for its permanent agricultural pumping service time of use option. Instead of having a separate tariff for this option, the Company proposes the time of use option be included in the Schedule 41 tariff with the time varying on-peak charge and off-peak credit being included in Schedule 201 prices. As discussed in my testimony concerning the proposed residential time of use pilot (Schedule 6), it is appropriate at this time to recover time varying energy charge differences through Schedule 201, because it is updated more regularly with the TAM than base rates are through general rate cases and its benefits, at least in the short-term, are primarily related to power cost expense. In the long run, if a significant level of irrigators adopt the time of use option and shift their load to off-peak, the Company anticipates potential system capacity benefits for which the agricultural pumping class will receive a further benefit in the form of lower allocations in cost of service through the years.

Also, like the proposed Schedule 6 residential time of use pilot, the Company selected on-peak hours based upon high value prices using the Company's current forecast view of energy value consistent with RVOS. [17] Time-varying energy charges will only apply during the highest cost months of July, August, and September, which are referred to in the proposed tariff as Summer. To allow this time of use option to be scalable in consideration of customers who pump from water projects, participants would have the option of selecting one of two four hour blocks of time to be on-peak based upon the highest eight hours in the summer season. The on-peak periods for the two proposed options are as follows:

- Option A – 2:00 p.m. to 6:00 p.m., all days in Summer.
- Option B – 6:00 p.m. to 10:00 p.m., all days in Summer.

Q. How were rates for the Schedule 41 time of use pilot calculated?

A. Page 3 of Exhibit PAC/1412 shows the ranking of prices by for the summer months of July through September. Option A comprises the first four-hour block of time in the highest eight hours and Option B comprises the second block of hours. Page 3 of Exhibit PAC/1412 shows that the difference in the average price for the on-peak Option A time and all other hours in the summer season is about $8.16 per MWh. The difference in the average price for the on-peak Option B time and all other hours in the summer season is about $11.69 per MWh. Averaging both periods yields a difference of about $9.92 per MWh. For Schedule 41 time of use option, the total off-

[16] *See* Order No. 19-021 in Docket No. UM 1910 at 9.

peak Summer price was set at the proposed total energy price for Schedule 41 less 0.992 cents per kWh. Designing the time of use option to be revenue neutral, the on-peak price was set at an amount where the same level of revenue would be recovered from Schedule 41 if the entire class were to be on the option with its current forecast load profile. Exhibit PAC/1414 shows the calculation of proposed Schedule 41 time of use option prices.

Schedule 48/748 – Large General Service (greater than 1,000 kW)

Q. Please explain the proposed tariffs for large general service customers.

A. For Schedules 48/748, Large General Service, the Company has proposed to modify base prices, at different voltage levels, to collect the target functionalized revenue requirement. For partial requirements customers served on Schedule 47/747, most prices are linked to changes in Schedule 48/748 prices. Changes to Schedule 48/748 continue to flow through to Schedule 47/747. The Company proposes a couple of notable changes to the current Schedule 48/748 rate structure—modernization of the time of use periods and a larger on- to off-peak energy charge differential.

Q. Why is the Company seeking to update its time of use periods for Schedule 48?

A. Schedule 48 customers are subject to mandatory time varying energy and demand charges. Current Schedule 48 specifies the on-peak period as 6:00 a.m. to 10:00 p.m., Monday through Friday excluding North American Electric Reliability Corporation holidays. This wide 16 hour block of on-peak sends a price signal for customers to shift their usage to the nighttime hours. Observing page 1 of Exhibit PAC/1412, nighttime is not the only low cost period. The middle of the day is also a very low cost period. The greater prevalence of solar on the western grid has increasingly lowered wholesale power prices in the middle of the day.[18] Modernizing the time periods for large non-residential customers to prioritize a shorter on-peak window has many benefits for the Company and its customers. With a shorter on-peak period, conservation and load shifting can be more targeted to the most stressful times for the grid. Moving load from the late afternoon to the middle of the day may also help to better align consumption with renewable output.

Q. What on-peak period does the Company propose for Schedule 48?

A. The Company proposes that the on-peak period for Schedule 48 be from 1:00 p.m. to 11:00 p.m. during all days in the summer months of July through September, and from 5:00 a.m. to 9:00 a.m. and 4:00 p.m. to 12:00 a.m. (midnight) during all days in the non-summer months of October through June. Page 4 of Exhibit PAC/1412 shows that this captures the highest 10 hours in the summer months and the highest 12 hours in the winter months. This reflects more on-peak hours than were proposed for the residential time of use pilot which considers the top six hours in the summer and the top eight hours in the winter. The Company proposes more on-peak hours for Schedule 48 to maintain revenue stability, because time varying rates are mandatory for Schedule 48 and the demand charge, which recovers a significant proportion of fixed costs, is based upon maximum kW usage during on-peak.

[17] *See* Christian Roselund, PV Magazine, *Solar Drives Up Evening Wholesale Prices in California* (July 24, 2017), https://pv-magazine-usa.com/2017/07/24/solar-drives-up-evening-wholesale-prices-in-california/; American Public Power Association, *California sets record for Solar, Renewable Curtailments* (June 25, 2019), https://www.publicpower.org/periodical/article/calif-sets-record-solar-renewable-curtailments.

Q. What price does the Company propose for on- and off-peak energy for Schedule 48?

A. Presently, the difference in the on- and off-peak energy charges for Schedule 48 is $1 per MWh. Page 4 of Exhibit PAC/1412 shows that difference in value between the proposed on- and off-peak periods is $7.39 per MWh. The Company proposes applying this differential to on- and off-peak energy charges in Schedule 201. The total proposed energy charge for a secondary voltage Schedule 48 customer would be 5.339 cents per kWh for on-peak energy and 4.600 cents per kWh for off-peak energy.

Q. What price does the Company propose for the on-peak kW demand charge for Schedule 48?

A. To set the correct price for on-peak kW demand, the Company adjusted the billing units to reflect the proposed on-peak time periods. The Company proposes a demand charge of $9.38 per on-peak kW for secondary voltage customers.

Proposed Schedule 29 – Non-Residential Time of Use Pilot

Q. Please describe the Company's proposed Schedule 29 Non-Residential Time of Use Pilot.

A. The Company proposes a new optional time of use pilot program for non-residential customers whose loads are less than one MW and who would otherwise qualify for Schedule 23, Schedule 28 or Schedule 30. Schedule 29 would be available for up to

100 customers and would both charge customers different prices for energy based on time of use and recover demand-related costs through a different pricing structure.

Q. Please describe how energy prices would be time differentiated under proposed Schedule 29.

A. Schedule 29 would use the same on-peak period of 1:00 p.m. to 11:00 p.m. during all days in the summer months of July through September, and 5:00 a.m. to 9:00 a.m. and 4:00 p.m. to 12:00 a.m. (midnight) during all days in the non-summer months of October through June that the Company proposes for Schedule 48. To keep the pricing structure as simple as possible, a sur-credit would apply to off-peak energy.

Q. Please describe how demand-related costs would be recovered on proposed Schedule 29.

A. Unlike conventional demand charges to which general service customers are subject, Schedule 29 customers would pay declining kWh-per-kW energy charges. The first 50 kWh for each kW of demand will be charged a higher rate and all additional kWh-per-kW will be charged a lower rate. In effect this structure allows the Company to charge customers an average energy price that declines as load factor increases, much like demand charges do, but puts a cap on how high that average cost can be for low load factor customers.

Q. What are the benefits of this structure?

A. As the Company began investigating the roadblocks to transportation electrification, it realized that a significant impediment to the buildout of fast-charging infrastructure was the very high cost of energy that stations with low utilization face because of the demand charge. In response to this roadblock, the Company implemented Schedule

45, an optional rate for publicly available direct current (DC) fast-charging stations that substitutes time of use energy charges for demand charges for a transitional period of time. While Schedule 45 provides a limited opportunity to give publicly available DC fast-charging stations a reprieve from demand charges, the Company would like to explore a more broadly available time of use option that also minimizes the adverse bill impacts for very low load factor customers.

Other forms of transportation electrification could take advantage of proposed Schedule 29 such as bus charging or fleet charging where time of use rates could lower the incremental cost of off-peak charging and help the Company better manage around its peak periods. There may also be other beneficial applications for this rate option. For example, a fruit grower may want to install frost protection fans, but may only need to use those fans for a limited number of days in a year. Since this type of load's utilization is very low and demand charges would be very acutely felt, this fruit grower might instead turn to propane or diesel powered equipment. Limiting the impact of demand charges, while sending time-based price signals under this option, helps to make energy more affordable and opens up new opportunities for the Company's customers.

Q. Why is it reasonable for very low load factor customers to pay less on this option?

A. Demand or capacity is an important and significant cost driver. Customers' use of power at the same time that generation, transmission, and upstream distribution are peaking can drive the need for the Company to upgrade and expand its facilities over time. The demand charge, which measures the highest kW reading in any 15 minute interval during the monthly billing period, is an effective way to recover these costs, producing stability over time and charging customers based on the overall size of their loads. However, when the load factor, a measurement of a customer's energy utilization relative to peak demand, is very low, it becomes less likely that the customer's peak demand will coincide with the same time that the Company's system peaks. An examination of the profiles of all of the Schedule 23, 28 and 30 customers on the Company's load research sample shows this relationship. Figure 2 below shows how coincidence with the Company's 12 system peaks compares to load factor for its Schedule 23, 28 and 30 load research participants:

Figure 2. Schedule 23, 28 and 30 Coincidence with Monthly System Peaks as Compared to Individual Customer Load Factor

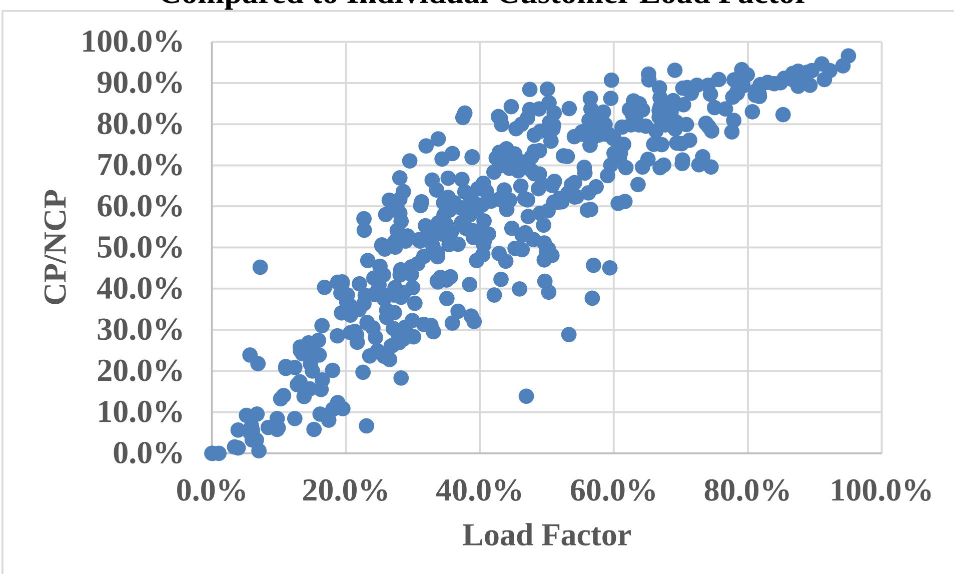


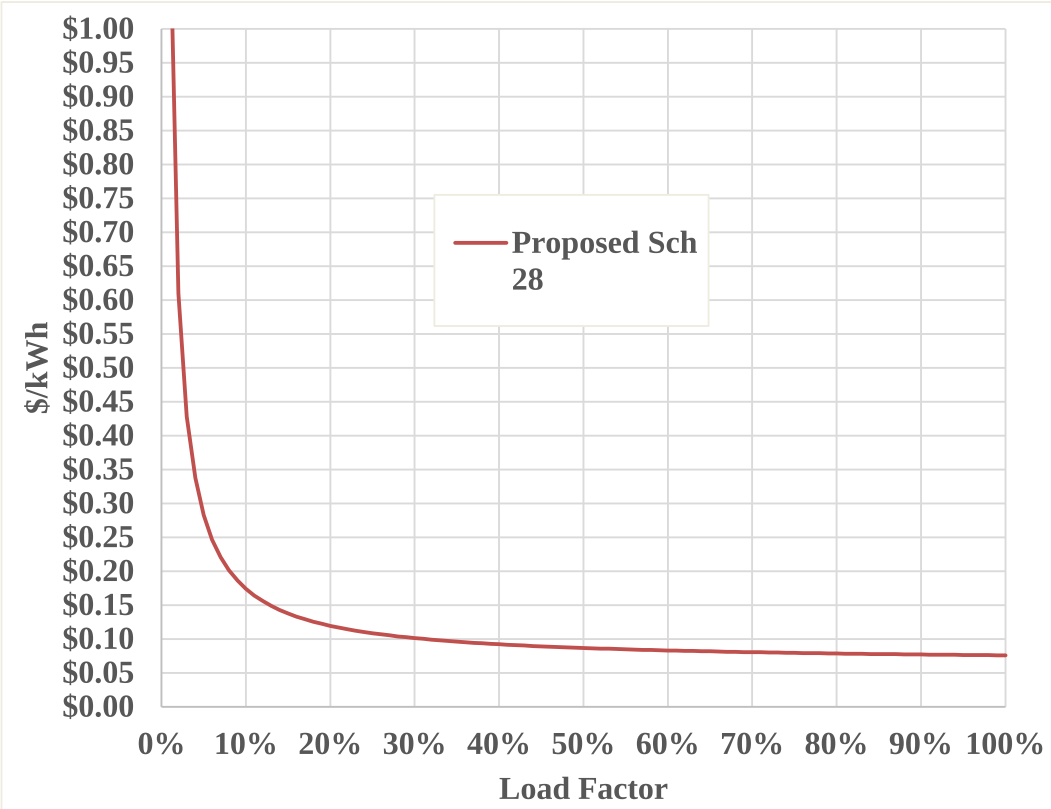
Figure 2 shows that as load factor decreases, the relationship between coincident peak (which is a key driver of costs) and non-coincident peak (which is how non-residential customers are billed for demand) gets weaker. Intuitively, this makes sense, because a 100 percent load factor customer would always hit the Company's peaks and conversely, using an extreme example, a customer who only used power for one hour in the year would be quite unlikely to use power during the Company's peak.

Customers on proposed Schedule 29 will be subject to time-differentiated energy prices and will still pay a higher average price if their load factor is low, but will effectively have the combined effect of their average demand and energy charges capped. Limiting the very high average price paid by low load factor customers is in recognition that coincidence with peak declines with load factor.

Q. How were proposed Schedule 29 prices calculated?

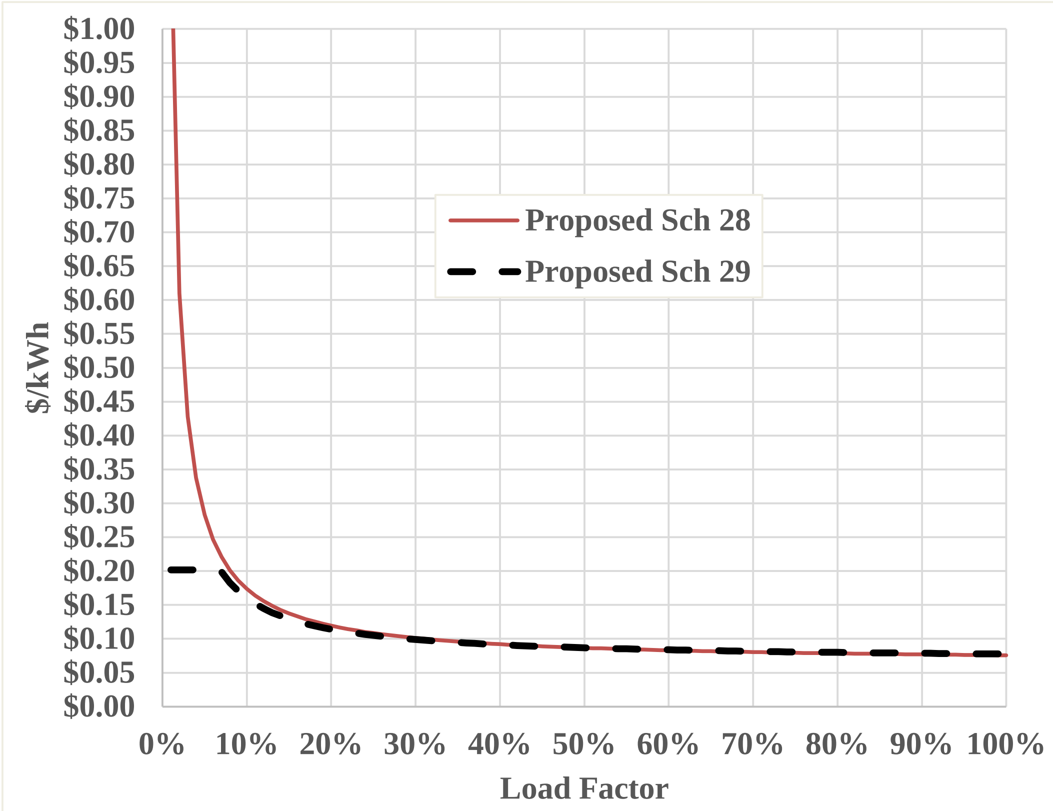
A. The prices proposed for Schedule 29 were based on Schedule 28 proposed rates. The off-peak credit was set to the 0.739 cent differential in value between the proposed on- and off-peak periods. It was then determined that 7.274 cents per kWh would be the average rate that would produce a value that, in concert with the off-peak credit, would be revenue neutral for Schedules 28. The Company then plotted the average energy cost for a 50 kW Schedule 28 customer using both the proposed $7.96 per kW cost for demand and facilities charges and the 6.808 cents per kWh average energy charge against load factor to better understand the relationship between average energy cost and load factor. Figure 3 shows this average demand and energy cost relative to load factor.

Figure 3. Average Demand and Energy Cost Relative to Load Factor for Combined Schedule 28 Prices



Through an iterative process of modifying the two different kWh-per-kW blocks, the Company developed a rate design that closely resembles the same average cost as shown on Figure 3. At 20.614 cents for the first 50 kWh-per-kW and 7.274 cents for all additional kWh, a very similar average cost can be achieved for all customers with load factors greater than about 29 percent. For customers with lower load factors, their average demand and energy cost would be effectively capped at 20.614 cents per kWh. Figure 4 shows how the proposed prices closely match the average demand and energy cost at different load factors.

Figure 4. Comparison of Proposed Schedule 29 Price to Average Energy and Demand Cost.



The Company proposes that the basic charge for Schedule 29 be set at $41.00 which is the weighted average price for the basic charge on Schedule 28. The calculation of proposed Schedule 29 prices is shown on Exhibit PAC/1415.

Q. Please describe any other features that are included in proposed Schedule 29.

A. The Company proposes that Schedule 29 participation be capped at 100 meters. After the Company has some experience and data on these customers, the Company can evaluate whether an expansion to the cap or any modifications to the tariff would be appropriate. Finally, the Company proposes that customers on Schedule 29 not be eligible for net metering service on Schedule 135. Since customers receiving service under Schedule 29 would only pay volumetric energy charges, it would not be reasonable for them to be able to entirely offset their bill with on-site generation whose exported energy is compensated for through energy credits valued at full retail energy rates. Demand charges send an important price signal to help balance the economics of customer generation. An eligible customer can always be served under the Company's standard general service and participate in net metering.

Large Customer Pilot Options

Q. What new pilot options does the Company propose for large non-residential customers?

A. The Company proposes Schedule 218, an optional interruptible service pilot where customers would receive bill credits in exchange for agreeing to interrupt their load when events are called. The Company also proposes Schedule 219, an optional real-time day-ahead pricing pilot where customers would have their energy charges shaped to hourly locational marginal prices that are available on a day-ahead basis.

Q. Why does the Company want to implement these two pilot programs?

A. As discussed earlier in my testimony, making energy more affordable, adapting to a more sustainable future, and giving customers options are important goals for the Company. Both of these options help the Company meet these goals by giving large customers different ways to provide the Company with more flexible loads in return for reductions to their bills. Large customers represent the greatest per meter opportunity for the Company to develop load flexibility. Large customers can also be very sophisticated energy users who may have the capability to respond to more complex pricing structures.

Q. Please describe how the interruptible service pilot would work?

A. Customers would enroll in the program and would nominate their non-interruptible load level, and any load in excess of that level would be interruptible. The Company would call interruption events when market prices are very high or when the Company's grid is under a lot of stress. Notice would be provided to customers at least 30 minutes in advance of each event. In response to each event, participants would need to reduce their load during the event down to the baseline non-interruptible load level they nominated. For example, a customer who typically uses 10 MW could choose to be interruptible down to three MW and would need to shed seven MW when the Company calls each event. In return for interrupting their load, participants would receive a $1 Interruptible Demand Credit applied to their Demand Charges for each of their on-peak kW during the monthly billing period and a 20 cent Interruptible Energy Credit for each kWh interrupted. The Company would call up to 100 hours of events each calendar year and would be able to call an event for up to three consecutive hours each day. Participation in the interruptible service pilot would require the Company to manually bill participants. To fully recover this cost, the Company proposes that participants would pay a $90 per month administrative fee. If necessary, customers would be responsible for any cost necessary to update the customer's metering to record settlement-quality five-minute interval data. Prior to updating the metering of a prospective participant, the Company will provide an estimate of the necessary cost. Proposed Schedule 218, which lays out all of the terms and conditions surrounding the program can be found in Exhibit PAC/1401.

Q. How did the Company determine the proposed prices for the Interruptible Demand Credit and the Interruptible Energy Credit?

A. Page 1 of Exhibit PAC/1416 shows the rationale behind the proposed prices for the Interruptible Demand Credit and the Interruptible Energy Credit. Real-time prices from EIM are a reasonable way to measure the value of energy at different times throughout the year. From specifically examining the Malin node which represents conditions at a point in between the Oregon and California border in the Company's service territory, the Company found that in the past three years of available data, there were less than 100 events each year where the real-time EIM price exceeded $200 per MWh. In the 12 months ended October 2017, there were 51 events where the real-time price exceeded $200 per MWh. During the 12 months ended October 2018, there were 74 events, and for 12 months ended October 2019, there were 46 events. For a program with up to 100 event hours per year, a 20 cent per kWh (which is the same as $200 per MWh) Interruptible Energy Credit is therefore reasonable. The Company will only be motivated to call events when the value of interruptions exceeds $200 per MWh and will likely have less than 100 hours each year when this occurs.

Page 1 of Exhibit PAC/1416 also shows that the value in excess of $200 per MWh during events when EIM prices exceeded $200 equates to about $0.63 per kW-month. For the purposes of the proposed interruptible pilot program, the Company recommends rounding this amount up to $1 for the Interruptible Demand Credit Price. The Company proposes to round this price up for two reasons. First, the Company believes that having at least a $1 per kW credit will be necessary to make the program sufficiently attractive for any large non-residential customers to participate. Second, the Company believes that in addition to energy benefits, there may be capacity value associated with an interruptible program, but experience operating the proposed pilot program can help determine an appropriate capacity value. Rounding the value up is in recognition of capacity and other potential benefits that the Company hopes to better understand with the operation of the pilot. One example of a potential capacity benefit would be avoiding long 16-hour block purchases of power to ensure that the Company has sufficient supply to meet loads.

Q. What accounting does the Company propose for the Interruptible Demand Credits and the Interruptible Energy Credits?

A. The Company proposes that both credits be treated as a NPC and be classified as purchased power expense. The Company also proposes that it be allocated on a System Generation interjurisdictional allocation factor. This treatment comports with the accounting and interjurisdictional allocations for other interruptible customer credits that exist on the east side of the Company's system (specifically in Utah and Idaho).

Q. What will happen if participants fail to perform and interrupt their load down to the nominated level?

A. The Company proposes a three strike system for when participants do not perform and interrupt their load down to their nominated level. The first time a participant does not fully interrupt their load, any interruptible credits will be forfeited for that particular billing month. The second time a participant fails to interrupt, all interruptible credits in the past six months will be forfeited. If a participant fails to interrupt for the third time in a rolling 12-month period, the customer will be removed from the program and will not be able to return for a year. The Company anticipates that these penalties will help to ensure that interruptible load which the Company relies on to serve its customers is available and participants perform the obligations that come with the benefits provided.

Q. Please provide an illustrative example of how a customer could save money on this program.

A. Page 2 of Exhibit PAC/1416 shows how the Interruptible Demand Credit and the Interruptible Energy Credit would work for a hypothetical five MW, 92 percent load factor customer who participates in the program. Without participating, this customer would pay about $2.413 million per year. Assuming 50 event hours get called during a year, this customer could save about 4.3 percent or about $109,000 for being interrupted in 0.6 percent of the hours in the year. This customer would receive $60,000 from the Interruptible Demand Credit and $50,000 from the Interruptible Energy Credit. This benefit would be offset by about $1,000 in administrative fees that recover the cost of billing for the program.

Q. Please describe how the real-time day-ahead pricing pilot would work?

A. Customers would sign up for the real-time day-ahead pricing pilot and would have the price that they pay for energy shaped by information provided by 1:00 p.m. the day before on the California Independent System Operator's (CAISO) Open Access Same-time Information System (OASIS) website. Specifically, the shape of energy prices would be based on the day-ahead market locational marginal price at the "ELAP_PACW-APND" node on the CAISO OASIS website (real-time day-ahead index) which is a rough representation of the general magnitude of hourly marginal energy cost on the PacifiCorp Control West balancing area. A participant could look at these prices the day before, scale back usage for hours and days when prices are elevated, and increase energy consumption when prices are low.

Q. How would energy be shaped on the hourly day-ahead prices provided?

A. Energy prices on Schedule 201 would be lower or higher depending upon how customer usage lines up with the real-time day-ahead index. At the end of each monthly billing period, the average price for the period on the real-time day-ahead index would be compared to the class average Schedule 201 price for the particular customer participating which is proposed in the concurrent TAM filing to be 2.136, 2.017, and 1.896 cents per kWh for secondary, primary and transmission voltage service, respectively. This average real-time day-ahead-index price for the period would be divided by the average Schedule 201 price to calculate an adjustment factor. If the average real-time day-ahead-index price was 4.800 cents per kWh for a particular month, the adjustment factor for a secondary voltage customer would be 0.500 (2.136/4.272). For that month, the customer would pay the hourly real-time price multiplied by the 0.500 adjustment factor. If the average real-time day-ahead-index price were 2.000 cents per kWh for the month, the adjustment factor for a secondary voltage customer would be 1.333 (2.136/1.602). For that month, the customer would pay the hourly real-time price multiplied by the 1.333 adjustment factor. In both cases, the adjusted hourly prices from the real-time day-ahead index for the month would be multiplied by the participant's energy usage in each hour to calculate overall Schedule 201 charges. In some hours, the prices from the real-time day-ahead index can be negative. Participants would see the benefit from usage during those hours, but total Schedule 201 charges for the full month would have a floor set at zero.

Q. Why does the Company propose this calculation be used to shape energy charges for participants?

A. Presently, all large over-one-MW general service customers are subject to mandatory time varying energy charges. In this rate case, the Company is proposing that the on- and off-peak differential be increased and the time of use periods be modernized. This provides a pretty good opportunity for large customers to save by shifting their usage to off-peak times that are clearly established and unchanging outside of rate cases. The on- and off-peak periods do a pretty good job of capturing high and low cost periods throughout the year. The real-time day-ahead pricing pilot, however, opens up an opportunity for customers to have their energy prices shaped in a far more detailed way to capture the different times when costs slump and spike. This pilot program is not intended to provide consumers with access to wholesale power markets. Direct access programs provide customers with that ability through energy service suppliers. Under the proposed program, the real-time day-ahead index prices would be adjusted to bring the magnitude of pricing in line with the levels paid by other non-participating customers. If the index's pricing is particularly high in a certain month, participants are only exposed to the variation of hourly prices within the month, not to the overall magnitude of any given month's pricing. Conversely, months with very low prices on the real-time day-ahead index would not create a windfall for participants, but would give them an opportunity to respond to the hourly variation in pricing within the month.

Q. How will demand charges be determined under the real-time day-ahead pricing pilot?

A. Schedule 48 customers pay demand charges that are based upon the highest kW reading during any 15-minute intervals that fall with the on-peak period defined on the Schedule 48 tariff. For a customer participating in the pilot, the on-peak period may not totally align with periods of lower pricing on the real-time day-ahead index. This could be problematic for a lower load factor customer who avoids demand charges by using energy outside the on-peak windows, but who has a high degree of flexibility and would otherwise be an excellent candidate for the pilot program. The Company therefore proposes that demand charges for the pilot program would be based upon the highest kW reading during any 15-minute interval that occurs during the highest priced 100 hours on the real-time day-ahead index during each monthly billing period. This allows the timing of demand charges to align with the higher cost periods on the pilot.

Q. Are there any other proposed features for the real-time day-ahead pricing pilot?

A. Yes. Like the interruptible service pilot, the Company proposes that a $90 per month administrative fee be charged to recover the cost of manually billing participants on the program. The Company also proposes that participants would be able to nominate a baseline quantity of load that could be exempted from participation. For example, a participant that has a 10 MW load could nominate three MW of baseline non-participating load. For this customer, in any given hour the first three MW would pay standard retail rates and all additional MW would be subject to the pricing and rules of the real-time day-ahead pricing pilot described on Schedule 219. Proposed Schedule 219, which lays out how the pilot would work, can be found in Exhibit PAC/1401.

Q. Does the Company anticipate using the "ELAP_PACW-APND" node on the CAISO OASIS website indefinitely for this program?

A. No. As discussed earlier, prices on CAISO's "ELAP_PACW-APND" node are generally capable of approximating the magnitude of hourly energy costs for the Company and that information is reasonable for shaping energy for the purposes of this pilot, but it is not perfect. One of the chief advantages of these data is that they are publicly available and updated daily by a third party and therefore can be used right away for this pilot. As discussed in Mr. Wilding's testimony, the Company is under contract with CAISO to develop nodal prices for PacifiCorp's system which will more accurately capture costs and better represent different points on the Company's system. Longer term, the Company would like to use this more detailed nodal pricing for any real-time pricing option(s). When it is available and set up in a format to deliver to customers, the Company anticipates it would make a filing with the Commission to update the real-time day-ahead index.

Q. Please provide illustrative examples of how a customer could save money on this program.

A. Page 1 of Exhibit PAC/1417 shows at a high level how the billing would work for an illustrative five MW, 92 percent load factor customer who participates in the pilot and chooses to avoid the two highest cost hours each day. The real-time day-ahead index for the 12 months ended June 2019 was used. In January, the average real-time day-ahead index is 4.025 cents per kWh which, when compared to the average 2.017 cents per kWh Schedule 201 price for Schedule 48 primary customers, produces an adjustment factor of 0.50. This gets applied to the participant's average price on the index of 3.843 cents per kWh to produce an average Schedule 201 price for the participant of 1.926 cents per kWh. The adjustment factors for each of the months ranges from a high of 1.10 in May to 0.26 in February. In each month, the customer achieves a lower average Schedule 201 energy price by cutting back load during the two highest hours each day. For the full year, this hypothetical customer would be able to save about 2.8 percent or about $70,000.

Page 2 of Exhibit PAC/1417 shows the billing for another illustrative participant with a five MW load, but who has a 25 percent load factor. This customer only chooses to use energy when the price is 73 percent less than a rolling average of the prior 15-day period. This customer avoids demand charges during all months and pays a lower rate by avoiding costlier hours. For the full year, this hypothetical customer would be able to save about 13 percent, or about $70,000.

Q. Does the Company propose caps on participation for the interruptible service and real-time day-ahead pricing pilots?

A. Yes. For each program, the Company proposes a cap of 25 MW of participation. Twenty-five MW is the minimum size for which the Company may trade energy on wholesale markets and is a reasonable sized cap that the Company believes will give it some experience with these programs while also limiting any potential risk to non-participating customers. To ensure that a single large customer does not take up the entire cap, the Company proposes that for both pilots a customer may only enroll up to 10 MW of load. Depending upon how well the pilots perform at providing both the Company and customers with meaningful value, the Company may request further expansion of the proposed programs.

Q. Is there value in offering these programs, if ultimately no customers participate in the proposed interruptible service pilot or real-time day-ahead pricing pilot?

A. Yes. Even if no customers ultimately enroll in either program, the Company will learn that the pilots are not sufficiently attractive to entice participation.

Street Lighting Price Re-Design

Q. What does the Company propose for lighting customers?

A. For Company-owned street and area lights, the Company proposes re-designing the prices to be based on the level of lighting service that the Company is providing, rather than on technology (*i.e.*, bulb) type. The Company also proposes creating a new "Customer-Funded LED Conversion" option for Company-owned street lights.

Q. Please provide a brief overview of the Company's current pricing structure for Company-owned lighting?

A. The Company currently offers service to Company-owned lights under the following schedules:

- Schedule 15 – Outdoor Area Lighting – No New Service
- Schedule 50 – Mercury Vapor Street Lighting Service – No New Service
- Schedule 51 – Street Lighting Service Company-Owned System
- Schedule 52 – Street Lighting Service Company-Owned System – No New Service

Street lights are provided for governmental entities to illuminate public streets, highways, and thoroughfares. Area lights, which are currently closed to new service, are provided to residential and non-residential customers to light spaces outside such as driveways or alleys. Prices for Company-owned street and area lights are based on the particular technology and type of lamp that the Company is providing. For example, a 7,000 lumen mercury vapor area light is $9.40 per month and a 4,000 lumen LED street light is $6.47. Schedule 52, which is closed to new service, charges a price per kWh plus a flat fee for the estimated operations and maintenance cost that is unique to different installations and has been in place for many years. Schedule 50 is for legacy mercury vapor lamps that the Company no longer offers. Schedule 50 charges different prices based on the type of pole and whether a lamp is served from overhead or underground facilities. For example, a 55,000 lumen mercury vapor, served from overhead facilities and installed on a wood pole is $34.79 per month. In summary, pricing for Company-owned lights is complicated.

Q. What does it mean to base prices for Company owned street and area lighting on level of service?

A. Presently, prices for Company-owned street and area lights are based on the particular technology and type of lamp that the Company is providing. The time is right to move away from this model for pricing lights that the Company owns and maintains. Ultimately, what the Company provides street and area lighting customers is a level of light to a specific area. The Company therefore proposes that Company-owned street and area light prices be based on the level of lighting service that the Company provides irrespective of technology or lamp type. The level of lighting service would be based on ranges of LED equivalent lumens. Under this new paradigm, an LED, a mercury vapor, and a high pressure sodium vapor lamp that provide the same level of light would have the same price. For area lights, the Company proposes the following levels:

- 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)

For street lights, the Company proposes the following levels:

- 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)

Q. Why is the Company proposing this change to the way it prices Company-owned street and area lights?

A. There are two reasons why the Company proposes this change. First, basing prices on service level better aligns the Company's incentives towards providing the provision of lighting at the lowest possible cost. LED has emerged as the dominant lighting technology and is the most efficient way to light a space, but the present structure of its rates disincentivizes the Company from converting lights to LED. If the Company replaces an older light with LED, its revenue decreases to reflect the lower-priced LED lamp. Basing the price for Company-owned lights on level of service will provide the Company with an incentive to transition its fleet of lights to the most efficient technology available.

Second, the Company's present prices for Company-owned lighting service are hard to understand. Simplifying them to specific ranges of light levels makes it easier for customers to understand.

Q. What is the "Customer-Funded LED Conversion" option?

A. Presently, street lighting customers can save by requesting that the Company-owned lights they pay for get converted to LED. Because this lowers the Company's revenue, the customer does not get a line extension allowance and pays for the full cost of the conversion. This provides customers with an opportunity to invest in more efficient technology and save on their monthly electric bill. While the proposed new level of service pricing paradigm for Company-owned lights removes a disincentive for the Company to convert to LED, the Company does not want to eliminate the incentive for customers to fund conversion of street lights to LED. The Company also wants to ensure fairness for early adopters who have paid to have the street lights serving them converted to LED. The Company proposes lower street light prices would be available in the tariff for "Customer-Funded Conversion" reflecting the lower marginal cost of lamps whose luminaires have been paid for by customers. While the Company plans to convert the lights to LED when it makes sense to do so,[19] that may be too slow for some customers who want the most energy efficient street lights in their community now.

Q. Did you prepare an exhibit that shows which existing street and area lighting prices change to the different proposed price based upon level of service?

A. Yes. Pages 1 and 2 of Exhibit PAC/1418 shows the different existing prices for Company-owned street and area lighting as well as the prices and levels of service that each type would change to under the Company proposed tariff revisions. With the Company's proposed level of service approach to pricing Company-owned lights,

[18] For example, the Company would convert a light to LED instead of fixing legacy equipment when it fails.

legacy Schedules 50 and 52 that are closed to new service would be canceled and customers on those schedules would go onto Schedule 51. Page 3 of Exhibit PAC/1418 shows a consolidated list of proposed prices for Company-owned street and area lighting for reference. With the Company's proposed pricing, the count of unique street and area lighting charges goes from 90 prices to 29 prices.

Q. How were prices set for the street and area lighting schedules?

A. In the Company's marginal cost of service study, marginal costs are developed for the street and area lighting class in the following way:

- Schedule 53 - Customer-Owned Street Lights – Marginal energy costs as well as commitment-related distribution costs are developed for this schedule. Service on Schedule 53 is un-metered, so metering costs are not included.
- Schedule 54 – Recreational Field Lighting – Marginal costs are developed in the same way as for Schedule 51, except the marginal cost of metering is included.
- Schedules 15, 50, 51 and 52 – Company-Owned Street and Area Lights - Marginal costs are developed in the same way as for Schedule 53, except the marginal cost of light ownership is included. This comprises the marginal cost of light installation as well as the marginal cost of light maintenance. For the newly created "Customer-Funded LED Conversion" option, the marginal cost of light installation is excluded.

In the Company's last marginal cost of service study, marginal costs for Company-owned lights which were closed to new service were not calculated. Additionally, since LED was a relatively new technology for the Company, the marginal cost for LED lamps was not developed. Marginal costs were therefore calculated for only four different high pressure sodium vapor street lights.

The energy output and maintenance costs for LED technology far exceeds other formats like high pressure sodium vapor and metal halide. Moving forward, the Company plans to only offer new service for Company-owned street and area lights that are LED and to transition its existing lights to LED over time. Consequently, the marginal cost of providing a level of lighting to a specific space outside is the cost of owning and maintaining LED lamps. For the cost of service study in this case, the Company developed the marginal cost of LED light ownership for the three levels of service proposed for area lights, the six levels of service proposed for street lights where the customer did not fund conversion, and the same six levels of service proposed for street lights where the customer did fund conversion (excludes the cost of light installation). In developing full marginal costs, the number of lamps that would fall under different service levels with Company's proposed pricing structure were applied to the marginal cost for each lamp type. Since the marginal cost of providing Company-owned lighting service is based on LED technology, the energy usage for each lamp type was assumed to be at what the Company's current standard LED lights use. For lighting (Schedules 15, 50, 51/751, 52/752, 53/753, and 54/754), the proposed revisions are designed to collect the overall functionalized target revenue requirement. Prices within each schedule and for each level of service for Company-owned lights are set at levels where prices reflect the relative differences in marginal cost.

Area Lights

Q. In addition to re-designing the Company-owned lamp prices, what other change does the Company propose for Schedule 15 – Outdoor Area Lighting Service?

A. The Company proposes that Schedule 15 be open to new service again on existing distribution poles only.

Q. Why has the Company closed its area light tariffs to new service?

A. My understanding is that the Company closed area lights for new service for two reasons. First, the Company was concerned about the costs associated with maintaining lights at homes and businesses throughout its service area. Second, the Company reasoned that a customer could always install an area light on its own side of the meter.

Q. Why is the Company requesting that Schedule 15 be opened up for new service again?

A. With LED technology, maintenance of area lights is far less than for other legacy lighting technologies. Whereas a high pressure sodium vapor lamp needs to have its bulb changed out every six years on average, an LED area light head is designed to last for 25 years. With the falling cost of LED lights, the Company can provide an efficient, low cost solution for its customers' outdoor lighting needs.

While customers can install area lights on their side of the meter, this is not always a good option for them. Sometimes the area that a customer wants to illuminate is much closer to distribution lines than to the customer's meter. In these circumstances, particularly in the Company's more rural service areas, running wire underground to a light a long distance away is not always cost effective or practical. Offering to own and maintain area lights can be a valuable service for customers.

Q. Why is the Company restricting new lamps to being on existing distribution poles only?

A. Installing new poles on customers' premises to provide area lighting service can increase maintenance costs for the Company and can also create access issues for service personnel who need to visit a lamp. Restricting new service to existing distribution poles mitigates these concerns.

IX. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 374
Exhibit PAC/1401
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Tariffs

February 2020

Index No.

Schedule No.

Schedule No.

PACIFIC POWER
A DIVISION OF PACIFICORP

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. (C)

Distribution Charge		
Single-Family Home Basic Charge, per month	$12.00	
Multi-Family Home Basic Charge, per month	$7.00	(C)
Three Phase Demand Charge, per kW demand	$2.20	
Three Phase Minimum Demand Charge, per month	$3.80	
Distribution Energy Charge, per kWh	3.822¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	0.820¢	(I)
System Usage Charge		
Schedule 200 Related, per kWh	0.084¢	(I)
T&A and Schedule 201 Related, per kWh	0.077¢	(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)

Issued February 14, 2020 **Effective for service on and after January 1, 2021**
Etta Lockey, Vice President, Regulation *Docket No. UE 374*

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 5

SEPARATELY METERED ELECTRIC VEHICLE SERVICE FOR RESIDENTIAL CONSUMERS
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To single-family Residential Consumers only for all single-phase and three-phase electric requirements supplied to electric vehicle charging installations where such service is supplied at a point of delivery separately metered from other residential service. Three-phase service will be supplied only when service is available from Company's presently existing facilities.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90. (C) (C)

Distribution Charge		
Single-Family Home Basic Charge, per month	$12.00	(C)
Multi-Family Home Basic Charge, per month	$7.00	
Three Phase Demand Charge, per kW demand	$2.20	
Three Phase Minimum Demand Charge, per month	$3.80	
Distribution Energy Charge, per kWh	3.822¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	0.820¢	(I)
System Usage Charge		
Schedule 200 Related, per kWh	0.084¢	(I)
T&A and Schedule 201 Related, per kWh	0.077¢	(I)

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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.

(N)

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 five thousand (5,000) 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
Multi-Family Home Basic Charge, per month	$7.00
Three Phase Demand Charge, per kW demand	$2.20
Three Phase Minimum Demand Charge, per month	$3.80
Distribution Energy Charge, per kWh	3.822¢
Transmission & Ancillary Services Charge	
Per kWh	0.820¢
System Usage Charge	
Schedule 200 Related, per kWh	0.084¢
T&A and Schedule 201 Related, per kWh	0.077¢

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

Seasonal Definitions	Summer:	July through September
	Non-Summer:	October through June
On-Peak Period	Summer:	All days 3 p.m. to 9 p.m.
	Non-Summer:	All days 6 a.m. to 8 a.m. and 5 p.m. to 11 p.m.
Off-Peak Period	All other hours.	

(N)

(continued)

(N)

Guarantee Payment
The Company shall guarantee against excessive increase of consumer costs for the first year of enrollment in the program. If the total energy costs incurred on this Schedule for the first year exceed 10% over what costs would have been for the same period under Cost-Based Supply Service, the net difference, Guarantee Payment, will be credited on the customer's bill following the end of the first year of serviced under the program. No Guarantee Payment shall be given if Consumer terminates service on the program before the end of the first year on the program.

Special Conditions

1. Consumers taking service under this schedule shall be subject to all conditions applicable to Schedule 4 of this tariff.

2. Participants for this program will be chosen on a first-come, first-served basis. Participation will be limited to approximately five thousand (5,000) metered points.

3. The Consumer must have a time-of-use capable meter installed to participate in this option. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under this schedule shall begin for the Consumer following the meter update and the initial meter reading.

4. Consumers requesting service under this pilot program agree to remain on the pilot for one year. Consumers will have the option to opt out of the pilot after this date by notifying the Company. Service will continue under this schedule until Consumer notifies the Company to discontinue service or this schedule terminates.

5. All Consumers participating in this pilot program may be asked to complete a survey regarding participation. Survey responses will be used to further evaluate the potential of future time-of-use rates. Data gathered will be used for pilot evaluation only.

6. Consumers on this tariff schedule shall have a term of not less than one year. Service will continue under this schedule until Consumer notifies the Company to discontinue service.

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.

(N)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 15

OUTDOOR AREA LIGHTING SERVICE -
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To all Consumers for outdoor area lighting service furnished from dusk to dawn by means of Company-owned lamps which may be served by secondary voltage circuits from the Company's existing overhead distribution system. Luminaires shall be mounted on Company-owned wood poles and served in accordance with the Company's specifications as to equipment and installation. Lamp installations on any pole except an existing distribution pole are closed to new service. (C) (C)

Monthly Billing

The Monthly Billing shall be the Rate Per Luminaire plus the applicable adjustments as specified in Schedule 90. (C)

Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate Per Lamp	
				(D)
Level 1	0-5,000	19	$8.76	(N)
Level 2	5,001-12,000	34	$10.08	(C)
Level 3	12,001+	57	$11.97	(C)
				(C)
				(D)

Supply Service Option

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Supply Service shall be provided by Supply Service Schedule 201.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, Transmission & Ancillary Services, Schedule 201, Net Power Costs, and distribution charges are collected through rates in this schedule.

Special Conditions

1. Inoperable lights will be repaired as soon as reasonably possible, during regular business hours or as allowed by Company's operating schedule and requirements, provided the Company receives notification of inoperable lights from Consumer or a member of the public by either notifying Pacific Power's customer service (1-888-221-7070) or www.pacificpower.net/streetlights. Pacific Power's obligation to repair street lights is limited to this tariff.

2. The Company reserves the right to contract for the maintenance of lighting service provided hereunder.

(continued)

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. (C)

Distribution Charge	**Delivery Voltage** Secondary	Primary	
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	$1.50	$1.50	(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	$5.08	$4.94	(I)
Distribution Energy Charge, per kWh	3.640¢	3.537¢	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.725¢	0.705¢	(I)
System Usage Charge			
Schedule 200 Related, per kWh	0.078¢	0.076¢	(I)
T&A and Schedule 201 Related, per kWh	0.070¢	0.068¢	(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)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 28

GENERAL SERVICE
LARGE NONRESIDENTIAL 31 KW to 200 KW
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90. (C)

	Delivery Voltage		
	Secondary	**Primary**	
Distribution Charge			
Basic Charge			
Load Size ≤50 kW, per month	$ 21.00	$ 29.00	(I)
Load Size 51-100 kW, per month	$ 39.00	$ 49.00	
Load Size 101 - 300 kW, per month	$ 93.00	$ 115.00	
Load Size > 300 kW, per month	$ 132.00	$ 164.00	
Load Size Charge			
≤50 kW, per kW Load Size	$ 1.30	$ 1.60	
51 - 100 kW, per kW Load Size	$ 1.05	$ 1.30	
101 – 300 kW, per kW Load Size	$ 0.65	$ 0.80	
> 300 kW, per kW Load Size	$ 0.40	$ 0.40	
Demand Charge, per kW	$ 4.45	$ 5.62	
Distribution Energy Charge, per kWh	0.450¢	0.089¢	
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
Transmission & Ancillary Services Charge			
Per kW	$ 2.21	$ 2.11	
System Usage Charge			
Schedule 200 Related, per kWh	0.086¢	0.080¢	
T&A and Schedule 201 Related, per kWh	0.077¢	0.072¢	(I)

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the demand charge. A higher minimum may be required under contract to cover special conditions.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 29

PILOT FOR GENERAL SERVICE TIME-OF-USE
DELIVERY SERVICE

Available (N)

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 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.

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	$41.00
Distribution Energy Charge	
First 50 kWh per kW demand, per kWh	13.419¢
All Additional kWh, per kWh	0.078¢
Transmission & Ancillary Services Charge	
Per kWh	0.739¢
System Usage Charge	
Schedule 200 Related, per kWh	0.086¢
T&A and Schedule 201 Related, per kWh	0.077¢

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. (N)

(continued)

(N)

On- and Off-Peak Definitions

Seasonal Definitions	Summer:	July through September
	Non-Summer:	October through June
On-Peak Period	Summer:	All days 1 p.m. to 11 p.m.
	Non-Summer:	All days 5 a.m. to 9 a.m. and 4 p.m. to 12 a.m. (midnight)
Off-Peak Period	All other hours.	

Special Conditions

1. Consumers taking service under this schedule shall be subject to all conditions applicable to Schedule 28 of this tariff.

2. Participants for this program will be chosen on a first-come, first-served basis. Participation will be limited to approximately one hundred (100) metered points.

3. The Consumer must have a time-of-use capable meter installed to participate in this option. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under this schedule shall begin for the Consumer following the meter update and the initial meter reading.

4. Consumers requesting service under this pilot program agree to remain on the pilot for one year. Consumers will have the option to opt out of the pilot after this date by notifying the Company. Service will continue under this schedule until Consumer notifies the Company to discontinue service or this schedule terminates.

5. All Consumers participating in this pilot program may be asked to complete a survey regarding participation. Survey responses will be used to further evaluate the potential of future rates. Data gathered will be used for pilot evaluation only.

6. Meters enrolled in this pilot will not be eligible to participate concurrently in net metering or any other generation related program offered by the Company.

Continuing Service

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal Consumer from minimum monthly charges.

Term of Contract

The Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

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.

(N)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 30

GENERAL SERVICE
LARGE NONRESIDENTIAL 201 KW to 999 KW
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedules 47 or 48. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90. (C)

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤200 kW, per month	$541.00	$538.00	(I)
Load Size 201 - 300 kW, per month	$161.00	$168.00	
Load Size > 300 kW, per month	$423.00	$437.00	
Load Size Charge			
≤200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$1.90	$1.85	
> 300 kW, per kW Load Size	$0.95	$0.90	
Demand Charge, per kW	$4.64	$4.64	
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kW	$2.52	$2.47	
System Usage Charge			
Schedule 200 Related, per kWh	0.082¢	0.081¢	
T&A and Schedule 201 Related, per kWh	0.074¢	0.073¢	(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)

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. (C) (C)

Distribution Charge	**Delivery Voltage** Secondary	Primary	
Basic Charge (November billing only)			
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$390.00	$380.00	(I)
Three Phase Load Size > 300 kW	$1,530.00	$1,490.00	
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$19.00	$18.00	
Three Phase 51 - 300 kW, per kW Load Size	$13.00	$13.00	
Three Phase > 300 kW, per kW Load Size	$8.00	$8.00	
Single Phase, Minimum Charge	$70.00	$70.00	
Three Phase, Minimum Charge	$115.00	$110.00	
Distribution Energy Charge, per kWh	4.464¢	4.338¢	(I)
Reactive Power Charge, per kVar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.645¢	0.627¢	(I)
System Usage Charge			
Schedule 200 Related, per kWh	0.074¢	0.072¢	
T&A and Schedule 201 Related, per kWh	0.096¢	0.093¢	(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of the Company's meter, or by appropriate test, for the 15-minute period of the Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

(continued)

kW Load Size *(continued)*

If Motor Size Is:	**Monthly kW is:**
2 hp or less	2 kW
Over 2 through 3 hp	3 kW
Over 3 through 5 hp	5 kW
Over 5 through 7.5 hp	7 kW
Over 7.5 through 10 hp	9 kW

In no case shall the Monthly kW be less than the average kW determined as:

$$\text{Average kW} = \frac{\text{kWh for billing month}}{\text{hours in billing month}}$$

Reactive Power Charge

The maximum 15-minute reactive takings for the billing month in kilovolt-amperes in excess of 40% of the Monthly kW.

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718.

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. A Small Nonresidential Consumer taking Delivery Service under this schedule shall additionally specify Supply Service Schedule 201, Schedule 210, Schedule 211, Schedule 212, Schedule 213, or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. A Large Nonresidential Consumer taking Delivery Service under this Schedule shall additionally 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 741, Direct Access Delivery Service.

Time-of-Use Options

Consumers taking service under this schedule who choose Supply Service Schedule 201 may also choose to participate in one of two time-of-use options, Option A and Option B, which provide time-varying rates during the Summer months of July, August and September. Rates and hours for these options are shown in Schedule 201. (N)

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.

(M) 41.3

(continued)

Special Conditions *(continued)*

1) For new or terminating service, the Basic Charge and the Load Size Charge shall be prorated based upon the length of time the account is active during the 12-month period December through November; provided, however, that proration of the Basic Charge and the Load Size Charge will be available on termination only if a full Basic Charge and Load Size Charge was paid for the delivery point for the preceding year. M (41.2)
2) For new service or for reestablishment of service, the Company will require a written contract. M (41.2)
3) In the absence of a Consumer or Applicant willing to contract for service, the Company may remove its facilities.
4) Energy use may be carried forward and be billed in a subsequent billing month; provided, however, that energy will not be carried forward and be charged for at a higher rate than was applicable for the billing months during which the energy was used.
5) A Consumer may not at the same time participate in one of the time-of-use options and Schedule 105 or any other demand response program. (N)

Term of Contract

Not less than three years.

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.

Issued February 14, 2020
Etta Lockey, Vice President, Regulation

Effective for service on and after January 1, 2021
Docket No. UE 374

On-Peak Period

The kWh shown by or computed from the readings of the Company's energy meter during on-peak hours. The on-peak period is
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.

Off-Peak Period (D)

All non On-Peak Period plus the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Seasonal Definition

Winter months are defined as November 1 through March 31. Summer months are defined as April 1 through October 31.

Special Conditions

1. At the option of the Consumer, service may be provided under the otherwise applicable General Service Schedule.
2. The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs. The sale of electricity for fuel to a motor vehicle is expressly allowed as described in Rule 2.E of this tariff.
3. A DC Fast Charger is defined for the purposes of eligibility on this rate schedule as a charging station with a Direct Current (DC) connection that has been designed to recharge the battery of an electric vehicle.
4. An electric vehicle charging site is considered to be broadly available to the general public for the purposes of eligibility on this rate schedule if it is available for use by any driver and is capable of charging more than one make of automobile. Eligibility and acceptance of a customer for service under this rate schedule is subject to review and approval by the Company.
5. Prior to receiving service under this rate schedule, the Consumer must disclose to the Company the number of chargers to be installed at the station, the type and capacity of each charger installed, and the maximum number of vehicles that can simultaneously use the station to recharge batteries.
6. The company reserves the right to terminate service under this schedule if it finds that excessive fees imposed by the charging station owner result in the charging station not being broadly available, per the requirements of this schedule.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 47

LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS 1,000 KW AND OVER
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 747, Direct Access Delivery Service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Reserves Charge, Transmission & Ancillary Services Charge, and System Usage Charge plus the applicable adjustments as specified in Schedule 90. (C)

	Delivery Voltage			
Distribution Charge	**Secondary**	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$640.00	$610.00	$820.00	(I) (I) (R)
Facility Capacity > 4,000 kW, per month	$1,220.00	$1,100.00	$1,520.00	(I) (I) (R)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$2.70	$1.20	$1.25	(I) (R) (R)
> 4,000 kW, per kW Facility Capacity	$2.60	$1.10	$1.25	(I) (R) (R)
On-Peak Demand Charge, per kW	$4.68	$4.83	$3.48	(I) (I) (R)
Reactive Power Charges				
Per kvar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Reserves Charges				
Spinning Reserves				
Per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company approved Self-Supply Agreement)				
Per kW of Spinning Reserves Level	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
Per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves (with Company-approved Load Reduction Plan or Self-Supply Agreement)				
Per kW of Supplemental Reserves Level	($0.27)	($0.27)	($0.27)	
Transmission & Ancillary Services Charge				
Per kW of On-Peak Demand	$2.22	$2.39	$3.19	(I) (I) (I)
System Usage Charge				
Schedule 200 Related, per kWh	0.076¢	0.075¢	0.073¢	(I) (I) (I)
T&A and Schedule 201 Related, per kWh	0.068¢	0.066¢	0.063¢	(R) (R) (I)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. Summer On-Peak hours are from 1 p.m. to 11 p.m. all days in the Summer months of July, August and September. Non-Summer On-Peak hours are from 5 a.m. to 9 a.m. and 4 p.m. to 12 a.m. (midnight) in the Non-Summer months of October through June. All remaining hours are Off-Peak. (C) (C) (C)

(D)

Metering Adjustment

A Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718.
A Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290.

Baseline Demand

The kW of Demand supplied by the Company to the Large Nonresidential Consumer when the Consumer’s generator is regularly operating as planned by the Consumer. For new Partial Requirements Consumers, the Consumer’s peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations, shall be used to calculate the Baseline Demand. Existing Partial Requirements Consumers shall select their Baseline Demand for each contract term based upon the Consumer’s peak demand for the most recent 12 months during the times the generator was operating as planned, adjusted for changes in load and planned generator operations. Planned generator operations includes changes in the electricity produced by the generator as well as the Consumer’s plans to sell any electricity produced by the generator to the Company or third parties. Any modification to the Baseline Demand must be consistent with Special Conditions in this schedule.

Facility Capacity

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, but shall not be less than the Consumer’s Baseline Demand. For new customers during the first three months of service under this schedule, the Facility Capacity will be equal to the Consumer’s Baseline Demand.

Reserves Charges

The Company provides Reserves for the Consumer’s Facility Capacity. Reserves consist of the following components:

Spinning Reserves

In addition to the Spinning Reserves provided for the Consumer’s Baseline Demand, Spinning Reserves provide Electricity immediately after a Consumer’s demand rises above Baseline Demand.

(continued)

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. (C)

Distribution Charge	**Delivery Voltage**			
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$640.00	$610.00	$ 820.00	(I) (I) (R)
Facility Capacity > 4,000 kW, per month	$1,220.00	$1,100.00	$1,520.00	(I) (I) (R)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$2.70	$1.20	$1.25	(I) (R) (R)
> 4,000 kW, per kW Facility Capacity	$2.60	$1.10	$1.25	(I) (R) (R)
On-Peak Demand Charge, per kW	$4.68	$4.83	$3.48	(I) (I) (R)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
Transmission & Ancillary Services Charge				
Per kW of On-Peak Demand	$2.76	$2.93	$3.73	(I) (I) (I)
System Usage Charge				
Schedule 200 Related, per kWh	0.076¢	0.075¢	0.073¢	(I) (I) (I)
T&A and Schedule 201 Related, per kWh	0.068¢	0.066¢	0.063¢	(R) (R) (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)

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. Summer On-Peak hours are from 1 p.m. to 11 p.m. all days in the Summer months of July, August and September. Non-Summer On-Peak hours are from 5 a.m. to 9 a.m. and 4 p.m. to 12 a.m. (midnight) in the Non-Summer months of October through June. All remaining hours are Off-Peak. (C) (C)

(D)

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718.

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290.

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 748, 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 not resell electric service received from the Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs.

Term of Contract

The Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 50

MERCURY VAPOR STREET LIGHTING SERVICE
NO NEW SERVICE
DELIVERY SERVICE

Available

In all territory served by the Company (except Multnomah County) in the State of Oregon.

Applicable

To service furnished from dusk to dawn for the lighting of public streets, highways, alleys and parks by means of presently-installed mercury vapor lights. Street lights will be served by either series or multiple circuits as the Company may determine. The type and kind of fixtures and supports will be in accordance with the Company's specifications. Service includes installation, maintenance, energy, lamp and glassware renewals.

Monthly Billing

The Monthly Billing shall be the Rate Per Luminaire plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

A. Company-owned Overhead System

Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)
Horizontal, per lamp	$5.74	$9.99	$19.43
Vertical, per lamp	$5.28	$9.18	

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)
On 26-foot poles, horizontal, per lamp	$7.84		
On 26-foot poles, vertical, per lamp	$7.32		
On 30-foot poles, horizontal , per lamp		$12.46	
On 30-foot poles, vertical, per lamp		$11.66	
On 33-foot poles, horizontal , per lamp			$21.87

B. Company-owned Underground System

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)
On 26-foot poles, horizontal, per lamp	$7.84		
On 26-foot poles, vertical, per lamp	$7.32		
On 30-foot poles, horizontal , per lamp		$11.95	
On 30-foot poles, vertical, per lamp		$11.19	
On 33-foot poles, horizontal , per lamp			$21.35
plus rate per foot of underground cable:			
In paved area	$0.05	$0.05	$0.05
in unpaved area	$0.03	$0.03	$0.03

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

Special Provisions

1. Installation, daily operation, repair and maintenance of lights on this rate schedule will be performed by the Company, providing that the facilities furnished remain readily accessible for maintenance purposes.
2. Inoperable lights will be repaired as soon as reasonably possible, during regular business hours or as allowed by Company's operating schedule and requirements, provided the Company receives notification of inoperable lights from Consumer or a member of the public by either notifying Pacific Power's customer service (1-888-221-7070) or www.pacificpower.net/streetlights. Pacific Power's obligation to repair street lights is limited to this tariff.
3. Existing fixtures and facilities that are deemed irreparable will be replaced with comparable high pressure sodium vapor fixtures and facilities from the Company's Construction Standards.
4. The Company will, upon written request of Consumer, convert existing streetlighting facilities to other types of Company approved facilities. In such event, should the revenue increase, the streetlighting extension allowance defined in Rule 13 Section III.F is applicable only to the increase in annual revenue due to the replacement. If there is no increase in revenue there is no allowance, The Consumer shall advance the estimated cost of all materials and labor associated with installation and removal, less the estimated salvage on the removed facilities, in excess of the applicable allowance.
5. Temporary disconnection and subsequent reconnection of electrical service requested by the Consumer shall be at the Consumer's expense. The Consumer may request temporary suspension of power by written notice. During such periods, the monthly rate will be reduced by the company's estimated average energy costs for the luminaire. The facilities may be considered idle and may be removed after 12 months of inactivity.
6. Pole re-painting, when requested by the Consumer and not required for safety reasons, shall be done at Consumer's expense using the original pole color.
7. Glare and vandalism shielding, when requested by the Consumer, shall be installed at the Consumer's expense. In cases of repetitive vandalism, the Company may notify the Consumer of the need to install vandal shields at the Consumer's expense, or otherwise have the lighting removed.

Supply Service Option

All Consumers shall pay the applicable rates in 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.

Termination of Service

The Consumer can request removal of lights with a minimum of 2 months written notice. The Consumer will be charged with the costs of removal.

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.

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. (C)

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	$ 7.14	$ 7.59	$ 7.76	$ 7.90	$ 8.43	$ 10.29
Functional Lighting - Customer Funded Conversion	$ 3.76	$ 3.99	$ 4.14	$ 4.25	$ 4.57	$ 5.60
Decorative Series	N/A	$ 13.28	$ 13.43	N/A	N/A	N/A

(C)
(C)
(D)
(N)

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.

(N)

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 751, Direct Access Delivery Service.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, Transmission & Ancillary Services, Schedule 201, Net Power Costs, and distribution charges are collected through rates in this schedule.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 52

STREET LIGHTING SERVICE COMPANY-OWNED SYSTEM
NO NEW SERVICE
DELIVERY SERVICE

Available

In all territory served by the Company (except Multnomah County) in the State of Oregon.

Applicable

To service furnished by means of the Company-owned installations, for the lighting of public streets, highways, alleys and parks under conditions and for street lights of sizes and types not specified on other schedules of this Tariff. The Company may not be required to furnish service hereunder to other than municipal Consumers. This schedule is closed to new service beginning November 8, 2006.

Monthly Billing

The Monthly Billing shall be the Rate Per kWh below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

A flat rate equal to one-twelfth of the Company's estimated annual cost for operation, maintenance, fixed charges and depreciation applicable to the street lighting system, including Distribution Charge as follows:

For dusk to dawn operation, per kWh	1.672¢
For dusk to midnight operation, per kWh	1.970¢

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 752, 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.

Term of Contract

Not less than five years for service to an overhead, or ten years to an underground, Company-owned system by written contract when unusual conditions prevail.

Provisions

1. Installation, daily operation, repair and maintenance of lights on this rate schedule will be performed by the Company, providing that the facilities furnished remain readily accessible for maintenance purposes.
2. Inoperable lights will be repaired as soon as reasonably possible, during regular business hours or as allowed by Company's operating schedule and requirements, provided the Company receives notification of inoperable lights from Consumer or a member of the public by either notifying Pacific Power's customer service (1-888-221-7070) or www.pacificpower.net/streetlights. Pacific Power's obligation to repair street lights is limited to this tariff.
3. Existing fixtures and facilities that are deemed irreparable will be replaced with comparable high pressure sodium vapor fixtures and facilities from the Company's Construction Standards.

(continued)

Provisions (continued)

4. The Company will, upon written request of Consumer, convert existing streetlighting facilities to other types of Company approved facilities. In such event, should the revenue increase, the streetlighting extension allowance defined in Rule 13 Section III.F is applicable only to the increase in annual revenue due to the replacement. If there is no increase in revenue, there is no allowance, The Consumer shall advance the estimated cost of all materials and labor associated with installation and removal, less the estimated salvage on the removed facilities, in excess of the applicable allowance.
5. Temporary disconnection and subsequent reconnection of electrical service requested by the Consumer shall be at the Consumer's expense. The Consumer may request temporary suspension of power by written notice. During such periods, the monthly rate will be reduced by the company's estimated average energy costs for the luminaire. The facilities may be considered idle and may be removed after 12 months of inactivity. The Company will not be required to re-establish such service under this rate schedule if service has been permanently discontinued by the Consumer.
6. Pole re-painting, when requested by the Consumer and not required for safety reasons, shall be done at Consumer's expense using the original pole color.
7. Glare and vandalism shielding, when requested by the Consumer, shall be installed at the Consumer's expense. In cases of repetitive vandalism, the Company may notify the Consumer of the need to install vandal shields at the Consumer's expense, or otherwise have the lighting removed.

Termination of Service

The Consumer can request removal of lights with minimum of 2 month's written notice. The Consumer will be charged with the costs of removal.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

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. (C)

High Pressure Sodium Vapor						
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000
Watts	70	100	150	200	250	400
Monthly kWh	31	44	64	85	115	176
Energy Only Service	$ 1.46	$ 2.08	$ 3.02	$ 4.01	$ 5.43	$ 8.31

(I)

Metal Halide					
Lumen Rating	9,000	12,000	19,500	32,000	107,800
Watts	100	175	250	400	1,000
Monthly kWh	39	68	94	149	354
Energy Only Service	$ 1.84	$ 3.21	$ 4.44	$ 7.04	$ 16.72

(I)

For non-listed luminaires the cost will be calculated for 4167 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire	¢/kWh
Energy Only Service	4.722

(I)

Maintenance Service (No New Service)

Where the utility operates and maintains the system, a flat rate equal to one-twelfth the estimated annual cost for operation and maintenance will be added to the Energy Only Service rates listed above. Monthly Maintenance is only applicable for existing monthly maintenance service agreements in effect prior to May 24, 2006.

(continued)

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. (C)

Distribution Charge

Basic Charge, Single Phase, per month	$ 6.00	
Basic Charge, Three Phase, per month	$ 9.00	
Distribution Energy Charge, per kWh	5.287¢	(I)

Transmission & Ancillary Services Charge

per kWh	0.039¢	(R)

System Usage Charge

Schedule 200 Related, per kWh	0.020¢	(R)
T&A and Schedule 201 Related, per kWh	0.015¢	(R)

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)

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: (D)

	Delivery Voltage			
	Secondary	**Primary**	**Transmission**	
Transmission & Ancillary Services Charge				
Per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.086	$0.093	$0.124	(I) (I) (I)
Daily ERP Demand Charge				
Per kW of Daily ERP On-Peak Demand	$0.182	$0.188	$0.136	(I) (I) (D)

Supply Service

A Consumer taking Delivery Service under this Schedule shall be served under the terms of Supply Service Schedule 276R.

ERP and ENF

Economic Replacement Power (ERP) is Electricity supplied by the Company to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Power Agreement (ERPA). ERP, ENF and ERPA are more fully described in Schedule 276R.

Daily ERP On-Peak Demand

Daily ERP On-Peak Demand shall not be less than the maximum ERP On-Peak Demand scheduled per day and shall not be greater than the difference between the Facility Capacity and the Baseline Demand. Daily ERP On-Peak Demand will be billed for each day in the month that the Company supplies ERP to the Consumer.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

GENERATION INVESTMENT ADJUSTMENT

Purpose

This schedule reflects an adjustment associated with the Lake Side 2 generation investment and interconnection, consistent with Order No. 13-474.

Applicable

To all Residential Consumers and Nonresidential Consumers.

Monthly Billing

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 kWh, and/or, as appropriate, kW, multiplied by the following applicable rate as listed by Delivery Service schedule.

Delivery Service Schedule	Secondary	Primary	Transmission
Schedule 4, per kWh	0.170¢		
Schedule 5, per kWh	0.170¢		
Schedule 15, per kWh	0.120¢		
Schedule 23, 723, per kWh	0.168¢	0.163¢	
Schedule 28, 728, per kWh	0.058¢	0.055¢	
Schedule 28, 728, per kW	$0.34	$0.29	
Schedule 30, 730, per kWh	0.055¢	0.054¢	
Schedule 30, 730, per kW	$0.40	$0.37	
Schedule 41, 741, per kWh	0.166¢	0.161¢	
Schedule 47, 747, per kWh	0.054¢	0.053¢	0.048¢
Schedule 47, 747, per On-Peak kW	$0.41	$0.45	$0.62
Schedule 48, 748, per kWh	0.054¢	0.053¢	0.048¢
Schedule 48, 748, per On-Peak kW	$0.41	$0.45	$0.62
Schedule 50, per kWh	0.120¢		
Schedule 51, 751, per kWh	0.120¢		
Schedule 52, 752, per kWh	0.120¢		
Schedule 53, 753, per kWh	0.120¢		
Schedule 54, 754, per kWh	0.120¢		

Rates "per kWh" shall apply to all kilowatt-hours of use per month.
Rates "per kW" and "per On-Peak kW" shall be charged based on measured monthly Demand and On-Peak Demand, respectively, as defined in each respective Delivery Service schedule.

CANCELLED

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 90

The following summarizes the applicability of the Company's adjustment schedules

SUMMARY OF EFFECTIVE RATE ADJUSTMENTS

Schedule	91	93	95	96	97	98*	104	192	195	197	202*	203*	204	205	206	207	290	293	294*	295*	296*	297*	299	(N) (D)
4	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x					x	x	(N)
5	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x					x	x	
15	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x		x			x	x	
23	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x		x			x	x	
28	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x		x			x	x	
30	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x		x			x	x	
41	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x			x	x	
47	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x			x	x	
48	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x			x	x	
51	x	x	x	x			x	x	x	x	x	x	x	x	x	x	x		x			x	x	(D)
53	x	x	x	x			x	x	x	x	x	x	x	x	x	x	x		x			x	x	(D)
54	x	x	x	x			x	x	x	x	x	x	x	x	x	x	x		x			x	x	
60																	x							
723	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x		x			x	x	
728	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x		x			x	x	
730	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	
741	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x			x	x	
747	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	
748	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	
751	x	x	x	x			x	x	x	x	x	x	x	x	x	x	x		x			x	x	(D)
753	x	x	x	x			x	x	x	x	x	x	x	x	x	x	x		x			x	x	
754	x	x	x	x			x	x	x	x	x	x	x	x	x	x	x		x			x	x	
848	x		x				x										x	x						

*Not applicable to all consumers. See Schedule for details.

Purpose

The purpose of this Schedule is to collect funds for electric low-income bill payment assistance as specified in ORS 757.612 Section (7)(b).

Applicable

To all bills for electric service calculated under all tariffs and contracts.

Adjustment Rates

The applicable Adjustment Rates are listed below. Retail electricity Consumers shall not be required to pay more than $500 per month per site for low-income electric bill payment assistance.

Schedule	Adjustment Rate	
Residential Rate Schedules (4, 5, 6)	69 cents per month	(C)
Nonresidential Rate Schedules	0.069 cents per kWh for the first 724,638 kWh	(C)

Definition of Site (Order No. 01-073 entered January 3, 2001)

"Site" means:

(a) Buildings and related structures that are interconnected by facilities owned by a single retail electricity consumer and that are served through a single electric meter; or

(b) A single contiguous area of land containing buildings or other structures that are separated by not more than 1,000 feet, such that:

i. Each building or structure included in the site is no more than 1,000 feet from at least one other building or structure in the site;

ii. Buildings and structures in the site, and land containing and connecting buildings and structures in the site, are owned by a single retail electricity consumer who is billed for electricity use at the buildings and structures; and

iii. Land shall be considered to be contiguous even if there is an intervening public or railroad right of way, provided that rights of way land, on which municipal infrastructure facilities exist (such as street lighting, sewerage transmission, and roadway controls), shall not be considered contiguous.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 98

ADJUSTMENT ASSOCIATED WITH THE PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT

All bills of qualifying residential customers on Schedule 4 and Schedule 5 shall have deducted an amount equal to the product of kilowatt-hours of use multiplied by the following cents per kilowatt-hour:

0-1000 kWh	0.934¢ per kWh
> 1000 kWh	0.000¢ per kWh

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).

All bills to qualifying nonresidential customers, and residential customers on Schedule 6, shall have deducted an amount equal to the product of all kilowatt-hours of use multiplied by the following cents per kilowatt-hour: (C)

0.691¢ 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 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").

Purpose

Service under this schedule is intended to maximize the efficient utilization of the electricity requirements of new and existing loads in Commercial and Industrial Facilities by promoting energy efficient design and the installation of Energy Efficiency Measures. No New Service after February 28, 2002.

Applicable

To service under the Company's General Service Schedules 23, 28, 30, 41, 47 and 48 in all territory served by the Company in the State of Oregon. This Schedule is not applicable to existing Commercial Buildings under 20,000 square feet. Square footage is the total Building or Facility area served by the Company's meter(s).

Customers using more than "one average megawatt" (8,760,000 kilowatt-hours of electricity per year) at a site may be required to sign a Company reimbursement agreement prior to receiving services or payments under this Schedule.

Description

Service under this program is available to improve the energy efficiency of eligible Commercial Buildings and Industrial Facilities connected to Company's system. The Company may provide Energy Efficiency Incentives which result in the installation of Energy Efficiency Measures, and also may provide for energy analyses inspections, savings verification and evaluation studies related to such Measures.

Definitions

Annual kWh Savings: The annual kilowatt-hour (kWh) savings resulting from installation of the Energy Efficiency Measures, as estimated by Company using engineering analysis.

Average Monthly On Peak kW Savings: The Average Monthly On Peak kilowatt (kW) savings resulting from the installation of Energy Efficiency Measures as estimated by Company using engineering analysis as described below:

Average Monthly On Peak kW Savings = (baseline average monthly On Peak kW - proposed average monthly On Peak kW), where;

⇒ Average monthly On Peak kW = sum of the 12 Monthly Maximum On Peak kW/12, where;
⇒ Monthly Maximum On Peak kW = highest of all 15 minute average kW (as determined below) for On Peak hours (6AM to 10PM, Monday through Saturday during the month), where;
⇒ 15 minute average kW = sum of kWh used over 0.25 hrs/0.25 hrs

(D)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 196

ADJUSTMENT TO REMOVE DEER CREEK MINE INVESTMENT
FROM RATE BASE

Purpose

This schedule implements adjustments to remove the undepreciated investment in the Deer Creek mine from rate base, as authorized by Order No. 15-161 in Docket UM 1712.

Monthly Billing

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No.36 will have applied an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service schedule.

Delivery Service Schedule	
Schedule 4, per kWh	-0.022¢
Schedule 5, per kWh	-0.022¢
Schedule 15, per kWh	-0.015¢
Schedule 23, 723, per kWh	-0.021¢
Schedule 28, 728, per kWh	-0.022¢
Schedule 30, 730, per kWh	-0.021¢
Schedule 41, 741, per kWh	-0.021¢
Schedule 47, 747, per kWh	-0.019¢
Schedule 48, 748, per kWh	-0.019¢
Schedule 50, per kWh	-0.015¢
Schedule 51, 751, per kWh	-0.015¢
Schedule 52, 752, per kWh	-0.015¢
Schedule 53, 753, per kWh	-0.015¢
Schedule 54, 754, per kWh	-0.015¢

This schedule will be terminated when base rates are reset in the Company's next general rate case.

Issued May 29, 2015
R. Bryce Dalley, Vice President, Regulation

Effective for service on and after June 1, 2015
Advice No. 15-009/Docket UM 1712

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 197R

GENERATION PLANT REMOVAL ADJUSTMENT

(N)

Purpose

This schedule recovers costs associated with the removal of certain generation plants, as authorized by the commission.

Monthly Billing

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No.36 will have applied an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service schedule.

Delivery Service Schedule	
Schedule 4, per kWh	0.136¢
Schedule 5, per kWh	0.136¢
Schedule 15, per kWh	0.043¢
Schedule 23, 723, per kWh	0.129¢
Schedule 28, 728, per kWh	0.130¢
Schedule 30, 730, per kWh	0.127¢
Schedule 41, 741, per kWh	0.123¢
Schedule 47, 747, per kWh	0.119¢
Schedule 48, 748, per kWh	0.119¢
Schedule 51, 751, per kWh	0.043¢
Schedule 53, 753, per kWh	0.043¢
Schedule 54, 754, per kWh	0.043¢

This schedule will terminate when ordered amounts have been fully recovered.

(N)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To all Residential Consumers and Nonresidential Consumers. This service may be taken only in conjunction with the applicable Delivery Service Schedule or Direct Access Delivery Service Schedule. Not applicable to energy usage under Delivery Service Schedule 76 which is billed at Economic Replacement Power rates under Schedule 276 or energy usage under Delivery Service Schedule 47 which is billed at Unscheduled Energy rates under Schedule 247.

Monthly Billing

The Monthly Billing shall be the Energy Charge and/or Demand Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.			Delivery Voltage Secondary	Primary	Transmission	
4	Per kWh	0 – 1000 kWh	3.279¢			(I)
		> 1000 kWh	3.779¢			(R)
5	Per kWh	0 – 1000 kWh	3.279¢			(I)
		> 1000 kWh	3.779¢			(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).

Delivery Service Schedule No.		Secondary	Primary	Transmission	
6	All kWh, per kWH	3.401¢			(N)
23, 723	First 3,000 kWh, per kWh	3.422¢	3.326¢		(I)
	All additional kWh, per kWh	2.540¢	2.468¢		(I)
28, 728	All kWh, per kWh	3.250¢	3.174¢		(I)
					(D)

(M)
200.2

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		Secondary	Primary	Transmission	
29	All kWh, per kWh	3.249¢	3.249¢		(N)
30, 730	Demand Charge, per kW	$1.95	$1.98		(M) 200.1 (I)
	All kWh, per kWh	2.631¢	2.591¢		(C)
	Demand shall be as defined in the Delivery Service Schedule				(D)
41, 741	All kWh	3.074¢	2.987¢		(M) 200.1 (C) (D)
47/48, 747/748	Demand Charge, per kW of On-Peak Demand	$1.94	$1.99	$2.03	(I)
	Per kWh, On-Peak	2.685¢	2.563¢	2.511¢	(I)
	Per kWh, Off-Peak	2.685¢	2.563¢	2.511¢	(I)

Delivery Voltage: Secondary, Primary, Transmission

Summer On-Peak hours are from 1 p.m. to 11 p.m. all days in the Summer months of July, August and September. Non-Summer On-Peak hours are from 5 a.m. to 9 a.m. and 4 p.m. to 12 a.m. (midnight) in the Non-Summer months of October through June. All remaining hours are Off-Peak. (C) (D)

On-Peak Demand shall be as defined in the Delivery Service Schedule.

(M) 200.3

15	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate Per Lamp	
	Level 1	0-5,500	19	$0.85	(C)
	Level 2	5,501-12,000	34	$1.53	(C)
	Level 3	12-001+	57	$2.56	(C)
					(C)
					(D)

(D)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

(D)

	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp	
51, 751	Level 1	0-3,500	8	$0.38	(C)
	Level 2	3,501-5,500	15	$0.71	
	Level 3	5,501-8,000	25	$1.18	
	Level 4	8,001-12,000	34	$1.60	
	Level 5	12,001-15,500	44	$2.08	
	Level 6	15,501+	57	$2.69	(C)

	Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
53, 753	High Pressure Sodium	5,800	70	31	$0.17	(R)
	High Pressure Sodium	9,500	100	44	$0.24	
	High Pressure Sodium	16,000	150	64	$0.35	
	High Pressure Sodium	22,000	200	85	$0.47	
	High Pressure Sodium	27,500	250	115	$0.63	
	High Pressure Sodium	50,000	400	176	$0.97	
	Metal Halide	9,000	100	39	$0.21	
	Metal Halide	12,000	175	68	$0.37	
	Metal Halide	19,500	250	94	$0.52	
	Metal Halide	32,000	400	149	$0.82	
	Metal Halide	107,800	1,000	354	$1.94	
	Non-Listed Luminaire, per kWh				0.549¢	(R)

54, 754 Per kWh 0.691¢ (M) 200.2

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential Consumers and Nonresidential Consumers who have elected to take Cost-Based Supply Service under this schedule or under Schedules 210, 211, 212, 213 or 247. This service may be taken only in conjunction with the applicable Delivery Service Schedule. Also applicable to Nonresidential Consumers who, based on the announcement date defined in OAR 860-038-275, do not elect to receive standard offer service under Schedule 220 or direct access service under the applicable tariff. In addition, applicable to some Large Nonresidential Consumers on Schedule 400 whose special contracts require prices under the Company's previously applicable Schedule 48T. For Consumers on Schedule 400 who were served on previously applicable Schedule 48T prices under their special contract, this service, in conjunction with Delivery Service Schedule 48, supersedes previous Schedule 48T.

Nonresidential Consumers who had chosen either service under Schedule 220 or who chose to receive direct access service under the applicable tariff may qualify to return to Cost-Based Supply Service under this Schedule after meeting the Returning Service Requirements and making a Returning Service Payment as specified in this Schedule.

Monthly Billing

The Monthly Billing shall be the Energy Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage**		
			Secondary	**Primary**	**Transmission**
4	Per kWh	0-1000 kWh	2.444¢		
		> 1000 kWh	3.340¢		
5	Per kWh	0-1000 kWh	2.444¢		
		> 1000 kWh	3.340¢		

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). (N)

6	Per kWh	All kWh	2.663¢		
	plus	per On-Peak kWh	7.050¢		
	plus	per Off-Peak kWh (credit)	-4.234¢		

For Schedule 6, Summer On-Peak hours are from 3 p.m. to 9 p.m. all days in the Summer months of July, August and September. Non-Summer On-Peak hours are from 6 a.m. to 8 a.m. and 5 p.m. to 11 p.m. in the Non-Summer months of October through June. Off-Peak hours are all remaining hours (N)

23	First 3,000 kWh, per kWh	2.708¢	2.623¢	
	All additional kWh, per kWh	2.007¢	1.946¢	
28	First 20,000 kWh, per kWh	2.649¢	2.549¢	
	All additional kWh, per kWh	2.574¢	2.481¢	

(M)
201.2

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		**Delivery Voltage** Secondary	Primary	Transmission	
29	All kWh, per kWh	3.044¢	3.044¢		(N)
	Plus per Off-Peak kWh (credit)	-0.739¢	-0.739¢		

For Schedule 29, Summer On-Peak hours are from 1 p.m. to 11 p.m. all days in the Summer months of July, August and September. Non-Summer On-Peak hours are from 5 a.m. to 9 a.m. and 4 p.m. to 12 a.m. (midnight) in the Non-Summer months of October through June. Off-Peak hours are all remaining hours. (M) 201.1

		Secondary	Primary	Transmission	
30	First 20,000 kWh, per kWh	2.831¢	2.800¢		
	All additional kWh, per kWh	2.454¢	2.420¢		(C)
41	All kWh, per kWh	2.589¢	2.512¢		
	Optional TOU Adders				(N)
	Plus per On-Peak kWh	4.989¢	4.989¢		(N)
	Plus per Off-Peak kWh (credit)	-0.992¢	-0.992¢		

Schedule 41 Consumers may choose to participate in one of two Time-of-Use (TOU) rate options, Option A and Option B which provide time-varying rates in the Summer months of July, August and September. Consumers may choose to participate in Option A with On-Peak hours from 2 p.m. to 6 p.m. all days in Summer or Option B with On-Peak hours from 6 p.m. to 10 p.m. all days in Summer. Off-peak hours for each Option are all other Summer hours which are not On-Peak. All other months have no time-of-use periods or rate adders.

		Secondary	Primary	Transmission
47/48	Per kWh On-Peak	2.497¢	2.317¢	2.176¢
	Per kWh, Off-Peak	2.447¢	2.267¢	2.126¢

For Schedule 47 and Schedule 48, Summer On-Peak hours are from 1 p.m. to 11 p.m. all days (C)
in the Summer months of July, August and September. Non-Summer On-Peak hours are from (C)
5 a.m. to 9 a.m. and 4 p.m. to 12 a.m. (midnight) in the Non-Summer months of October (C)
through June. Off-Peak hours are all remaining hours.

(D)

15	**Type of Lamp**	**LED Equivalent Lumens**	**Monthly kWh**	**Rate Per Lamp**	(C)
	Level 1	0-5,500	19	$TBD	(C)
	Level 2	5,501-12,000	34	$TBD	(C)
	Level 3	12-001+	57	$TBD	(C)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp	
					(D)
51	Level 1	0-3,500	8	$TBD	(C)
	Level 2	3,501-5,500	15	$TBD	
	Level 3	5,501-8,000	25	$TBD	
	Level 4	8,001-12,000	34	$TBD	
	Level 5	12,001-15,500	44	$TBD	
	Level 6	15,501+	57	$TBD	(C)
					(D)

	Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
53	High Pressure Sodium	5,800	70	31	$0.27	
	High Pressure Sodium	9,500	100	44	$0.38	
	High Pressure Sodium	16,000	150	64	$0.55	
	High Pressure Sodium	22,000	200	85	$0.73	
	High Pressure Sodium	27,500	250	115	$0.99	
	High Pressure Sodium	50,000	400	176	$1.52	
	Metal Halide	9,000	100	39	$0.34	
	Metal Halide	12,000	175	68	$0.59	
	Metal Halide	19,500	250	94	$0.81	
	Metal Halide	32,000	400	149	$1.29	
	Metal Halide	107,800	1,000	354	$3.06	
	Non-Listed Luminaire, per kWh				0.864¢	(T)
54	Per kWh	1.492¢				(M) 201.2

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 202

RENEWABLE ADJUSTMENT CLAUSE
SUPPLY SERVICE ADJUSTMENT

Purpose

This schedule recovers, between rate cases, the costs to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission.

This adjustment is to recover the actual and forecasted revenue requirement associated with the prudently incurred costs of resources, including associated transmission, that are eligible under Senate Bill 838 (2007) and in service as of the date of the proposed rate change. The revenue requirement includes the actual return of and grossed up return on capital costs of the renewable energy source and associated transmission at the currently authorized rate of return, forecasted operation and maintenance costs, forecasted property taxes, forecasted energy tax credits, and other forecasted costs not captured in the Transition Adjustment Mechanism (TAM). The revenue requirement for Oregon will be calculated using the forecasted inter-jurisdictional allocation factors based on the same 12-month period used in the TAM.

Applicable

To all Residential consumers and Nonresidential consumers except consumers who began service under the five-year cost of service opt-out program described in Schedule 296 before January 1, 2019.

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule.

Schedule	Charge	
4	0.075 cents per kWh	
5	0.075 cents per kWh	
15	0.124 cents per kWh	
23, 723	0.142 cents per kWh	
28, 728	0.152 cents per kWh	
30, 730	0.149 cents per kWh	
41, 741	0.154 cents per kWh	
47, 747	0.140 cents per kWh	
48, 748	0.140 cents per kWh	
51, 751	0.152 cents per kWh	(D)
53, 753	0.070 cents per kWh	
54, 754	0.099 cents per kWh	(D)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 203

RENEWABLE RESOURCE DEFERRAL
SUPPLY SERVICE ADJUSTMENT

Purpose

This schedule recovers the costs deferred for renewable resources as authorized by the Commission.

Applicable

To all Residential consumers and Nonresidential consumers except consumers who elected service under the five-year cost of service opt-out program described in Schedule 296 before November 2017.

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule.

Schedule	Charge	
4	0.005 cents per kWh	
5	0.005 cents per kWh	
15	0.004 cents per kWh	
23, 723	0.005 cents per kWh	
28, 728	0.005 cents per kWh	
30, 730	0.005 cents per kWh	
41, 741	0.005 cents per kWh	
47, 747	0.005 cents per kWh	
48, 748	0.005 cents per kWh	
51, 751	0.005 cents per kWh	(D)
53, 753	0.002 cents per kWh	
54, 754	0.003 cents per kWh	(D)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 204

OREGON SOLAR INCENTIVE PROGRAM DEFERRAL
SUPPLY SERVICE ADJUSTMENT

Purpose

This schedule recovers the costs deferred for the Oregon Solar Incentive Program as authorized in Docket UM 1483.

Applicable

To all Residential consumers and Nonresidential consumers.

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule.

Delivery Service Schedule	Charge	
4	0.038 cents per kWh	
5	0.038 cents per kWh	
15	0.029 cents per kWh	
23, 723	0.036 cents per kWh	
28, 728	0.037 cents per kWh	
30, 730	0.036 cents per kWh	
41, 741	0.037 cents per kWh	
47, 747	0.032 cents per kWh	
48, 748	0.032 cents per kWh	(D)
51, 751	0.038 cents per kWh	
53, 753	0.012 cents per kWh	(D)
54, 754	0.021 cents per kWh	

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 205

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.

Delivery Service Schedule No.			Delivery Voltage Secondary	Primary	Transmission	
4	Per kWh	0-1000 kWh	0.000¢			(R)
		> 1000 kWh	0. 000¢			
5	Per kWh	0-1000 kWh	0. 000¢			
		> 1000 kWh	0. 000¢			

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).

Delivery Service Schedule No.		Secondary	Primary	Transmission
23, 723	First 3,000 kWh, per kWh	0. 000¢	0. 000¢	
	All additional kWh, per kWh	0. 000¢	0. 000¢	
28, 728	First 20,000 kWh, per kWh	0. 000¢	0. 000¢	
	All additional kWh, per kWh	0. 000¢	0. 000¢	
30, 730	First 20,000 kWh, per kWh	0. 000¢	0. 000¢	
	All additional kWh, per kWh	0. 000¢	0. 000¢	
41, 741	Winter, first 100 kWh/kW, per kWh	0. 000¢	0. 000¢	
	Winter, all additional kWh, per kWh	0. 000¢	0. 000¢	
	Summer, all kWh, per kWh	0. 000¢	0. 000¢	

For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30. (R)

(continued)

Energy Charge (continued)

Delivery Service Schedule No.		**Delivery Voltage** Secondary	Primary	Transmission	
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 11 p.m. all days in the Summer months of July, August and September. Non-Summer On-Peak hours are from 5 a.m. to 9 a.m. and 4 p.m. to 12 a.m. (midnight) in the Non-Summer months of October through June. Off-Peak hours are all remaining hours. (C) (D)

(M)
205.3

15	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp	
	Level 1	0-5,000	19	$0.00	(C)
	Level 2	5,001-12,000	34	$0.00	(C)
	Level 3	12,001+	57	$0.00	(C)

(D)

(continued)

Energy Charge (continued)

Delivery Service Schedule No.

(D)

	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp	
51, 751	Level 1	0-3,500	8	$0.00	(C)
	Level 2	3,501-5,500	15	$0.00	
	Level 3	5,501-8,000	25	$0.00	
	Level 4	8,001-12,000	34	$0.00	
	Level 5	12,001-15,500	44	$0.00	
	Level 6	15,501+	57	$0.00	(C)

	Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
53, 753	High Pressure Sodium	5,800	70	31	$0.00	(R)
	High Pressure Sodium	9,500	100	44	$0.00	
	High Pressure Sodium	16,000	150	64	$0.00	
	High Pressure Sodium	22,000	200	85	$0.00	
	High Pressure Sodium	27,500	250	115	$0.00	
	High Pressure Sodium	50,000	400	176	$0.00	
	Metal Halide	9,000	100	39	$0.00	
	Metal Halide	12,000	175	68	$0.00	
	Metal Halide	19,500	250	94	$0.00	
	Metal Halide	32,000	400	149	$0.00	
	Metal Halide	107,800	1,000	354	$0.00	(R)

Non-Listed Luminaire, per kWh 0.000¢

54,754 Per kWh 0.000¢ (M) 205.2 (R)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 206

POWER COST ADJUSTMENT MECHANISM - ADJUSTMENT

Purpose

This schedule implements the Company's annual Power Cost Adjustment Mechanism adjustment consistent with Order No. 12-493.

Applicable

To all Residential Consumers and Nonresidential Consumers except Nonresidential Consumers who took service under Standard Offer Supply Service Schedule 220 or who were served under a Direct Access Delivery Service Schedule during the accrual period of this Power Cost Adjustment Mechanism adjustment.

Monthly Billing

The adjustment shall be calculated as an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service Schedule.

Delivery Service Schedule	Secondary	Primary	Transmission	
Schedule 4, per kWh	0.000¢			
Schedule 15, per kWh	0.000¢			
Schedule 23, 723, per kWh	0.000¢	0.000¢		
Schedule 28, 728, per kWh	0.000¢	0.000¢		
Schedule 30, 730, per kWh	0.000¢	0.000¢		
Schedule 41, 741, per kWh	0.000¢	0.000¢		
Schedule 47, 747, per kWh	0.000¢	0.000¢	0.000¢	
Schedule 48, 748, per kWh	0.000¢	0.000¢	0.000¢	(D)
Schedule 51, 751, per kWh	0.000¢			
Schedule 53, 753, per kWh	0.000¢			(D)
Schedule 54, 754, per kWh	0.000¢			

PACIFIC POWER
A DIVISION OF PACIFICORP

Purpose

This schedule recovers costs incurred for the start-up of the State of Oregon's Community Solar Program including the costs associated with the State of Oregon's Program Administrator, Low Income Facilitator and the Company's prudently incurred costs associated with implementing the program that are not otherwise recovered in rates. The recovery of these costs is authorized by ORS 757.386 (7)(c) and OAR 860-088-0160. This adjustment schedule is implemented as an automatic adjustment clause as provided under ORS 757.210 to allow recovery of operations and maintenance start-up costs as soon as the cost data is approved by the Commission.

Monthly Billing

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No.36 will have applied an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service schedule.

Delivery Service Schedule	
Schedule 4, per kWh	0.004¢
Schedule 5, per kWh	0.004¢
Schedule 15, per kWh	0.003¢
Schedule 23, 723, per kWh	0.003¢
Schedule 28, 728, per kWh	0.003¢
Schedule 30, 730, per kWh	0.003¢
Schedule 41, 741, per kWh	0.003¢
Schedule 47, 747, per kWh	0.003¢
Schedule 48, 748, per kWh	0.003¢
Schedule 51, 751, per kWh	0.003¢
Schedule 53, 753, per kWh	0.001¢
Schedule 54, 754, per kWh	0.002¢

Remittance of Funds

In accordance with Order No. 19-122 the Company will remit monthly payments for start-up services to the State of Oregon's Program Administrator and Low Income Facilitator within 15 days of notice from the Commission of the required remittance amount(s).

PACIFIC POWER
A DIVISION OF PACIFICORP

PORTFOLIO TIME-OF-USE SUPPLY SERVICE

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 sum of the Portfolio Service Charge and 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.

Portfolio Service Charge

$1.50 per month

Energy Charge

Delivery Service Schedule No.		Season Winter	Season Summer
4	On-Peak kWh, per kWh	3.316 ¢	6.124 ¢
	Off-Peak kWh, per kWh	(1.125)¢	(1.125)¢
5	On-Peak kWh, per kWh	3.316 ¢	6.124 ¢
	Off-Peak kWh, per kWh	(1.125)¢	(1.125)¢
23	On-Peak kWh, per kWh	4.365 ¢	9.350 ¢
	Off-Peak kWh, per kWh	(1.438)¢	(1.438)¢
41	On-Peak kWh, per kWh	3.737 ¢	8.004 ¢
	Off-Peak kWh, per kWh	(1.231)¢	(1.231)¢

Seasonal Definition

Winter months are defined as November 1 through March 31. Summer months are defined as April 1 through October 31.

Minimum Charge

The minimum monthly charge will be the Portfolio Service Charge.

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.

(D)

(continued)

(D)

Off-Peak Period

All non On-Peak Period plus the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Guarantee Payment

The Company shall guarantee against increase of consumer costs for the first 12 months of enrollment in the program. If the total annual energy costs incurred on this Schedule exceed 10% over what costs would have been for the same period under Cost-Based Supply Service, the net difference, Guarantee Payment, will be credited on the customer’s bill following the last month of the one-year commitment. The Portfolio Service Charge shall not be included in the calculation of the Guarantee Payment and shall not be credited. No Guarantee Payment shall be given if Consumer terminates service before the end of the initial one-year period.

Special Conditions

1. The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by written permission of the Company or as otherwise expressly provided in Company tariffs and where the Consumer meters and bills any of its tenants at the Company's regular tariff rate for the type of service which such tenant may actually receive.

2. The Company will recover any lost revenues and Guarantee Payment amounts incurred under the Portfolio Option through adjustments to Schedule 291 or Schedule 292.

3. Consumers on this tariff schedule shall have a term of not less than one year. Service will continue under this schedule until Consumer notifies the Company to discontinue service.

4. The Consumer must have a time-of-use meter installed to participate in this option. The Company anticipates that a delay may occur from the time a Consumer requests service under this option until the Company can provide the meter installation. In the interim, Consumers will receive service under the applicable Delivery Service schedule on Supply Service Schedule 201.

5. Billing under this schedule shall begin for the Consumer following installation of the time-of-use meter and the initial meter reading.

6. The Company will not accept enrollment for accounts that have:

   - Time-payment agreement in effect
   - Received two or more final disconnect notices
   - Been disconnected for non-payment within the last 12 months.

7. Service under this schedule will be labeled, "Time of Use".

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.

Purpose

To implement a pilot program for optional time-of-use rates for irrigation customers.

Available

To areas served by the Company in and around Klamath Falls and Albany, Oregon.

Applicable

To agricultural irrigation or agricultural soil drainage pumping Consumers receiving Delivery Service under Schedule 41, in conjunction with Supply Service Schedule 201, who have been invited to participate in this pilot and who elect to take this service. New participation in 2016 will be limited to approximately twenty-five (25) metered points of delivery. No more than two metered points of delivery belonging to one Consumer will be allowed into the pilot.

Monthly Billing

The Monthly Billing shall be the Energy Charge. The Monthly Billing is in addition to all other charges contained in Delivery Service Schedule 41, Base Supply Service Schedule 200 and Supply Service Schedule 201.

Energy Charge

		Prime Summer Season
41	On-Peak kWh, per kWh	22.313¢
	Off-Peak kWh, per kWh	(3.161)¢

Seasonal Definition

Prime Summer season is defined as June 1 through August 31. Time-of-use adders under this pilot apply for the Prime Summer season only. No adjustments will be applied in other months.

On-Peak Period

Prime Summer
Monday through Friday 2:00 p.m. to 6:00 p.m.

All other months have no time-of-use periods.

Off-Peak Period

Prime Summer
All non On-Peak Period hours and days plus the following holiday: Independence Day.

All other months have no time-of-use periods.

(continued)

Guarantee Payment

The Company shall guarantee against excessive increase of consumer costs for the 2014 and 2015 Prime Summers of enrollment in the program and thereafter for the first Prime Summer of enrollment. If the total energy costs incurred on this Schedule for the Prime Summer season exceed 10% over what costs would have been for the same period under Cost-Based Supply Service, the net difference, Guarantee Payment, will be credited on the customer's bill following the end of the Prime Summer season. No Guarantee Payment shall be given for a Prime Summer period if Consumer terminates service before the end of the Prime Summer period.

Special Conditions

1. In 2016, eligible Consumers in the Klamath Falls area will be invited via mail to participate in this pilot. Participants will be chosen on a first-come, first-served basis. New participation will be limited to approximately twenty-five (25) metered points. No more than two accounts belonging to one Consumer will be allowed into the pilot.

2. The Consumer must have a time-of-use meter installed to participate in this option. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. The replacement of older meters may result in more accurate metering. The Consumer will be responsible for all charges based on accurate meter measurements from new meters. Billing under this schedule shall begin for the Consumer following installation of the time-of-use meter and the initial meter reading. Rates under this schedule prior to the beginning of the Prime Summer time-of-use rate season will be standard cost-based rates.

3. Consumers requesting service under this pilot program beginning in 2015 agree to remain on the pilot through the end of the 2015 Prime Summer season, which ends on August 31, 2015. Consumers will have the option to opt out of the pilot after this date by notifying the Company. Service will continue under this schedule until Consumer notifies the Company to discontinue service or this schedule terminates. In the event that participants are added to the pilot after the 2015 Prime Summer season, such participants agree to remain on the pilot through the end of their first Prime Summer season of participation.

4. All Consumers invited to participate in this pilot program may be asked to complete a survey following the end of the Prime Summer season. Survey responses will be used to further evaluate the potential of future time-of-use irrigation rates. Data gathered will be used for pilot evaluation only.

5. Meters enrolled in this pilot will not be eligible to participate concurrently in any load control pilot which is offered by the Company.

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.

PACIFIC POWER
A DIVISION OF PACIFICORP

INTERRUPTIBLE SERVICE PILOT

Available (N)
In all territory served by the Company in the State of Oregon.

Applicable
To Nonresidential Consumers receiving Delivery Service under Schedule 48, in conjunction with Supply Service Schedule 201. Participation will be limited to the first twenty-five (25) megawatts of load on a first come, first served basis.

Monthly Billing

The Monthly Billing shall be the Interruptible Demand Credit, Interruptible Energy Credit, and Administrative Fee. The Monthly Billing is in addition to all other charges contained in Delivery Service Schedule 48, Base Supply Service Schedule 200 and Supply Service Schedule 201.

Interruptible Demand Credit

Per kW of On-Peak Interruptible Demand	-$1.00

Interruptible Energy Credit

Per kWh of Interrupted Energy	-20.000¢

Administrative Fee

Per month	$90.00

Interruption Events
The Company may call up to 100 hours of Interruption Events each calendar year. One Interruption Event may be called each day and may not exceed 3 consecutive hours. Each Interruption Event called by the Company shall be set for a period of at least 15 minutes in duration. Interruption Events may be called on any day or at any time during the year. During Interruption Events, a participant's usage shall not exceed their Baseline Non-Interruptible Load.

Interruption Notification
At least 30 minutes prior to an Interruption Event, the Company shall notify participants.

Interrupted Energy
Interruptible Energy during each Interruption Event shall be measured as the difference between the average load in kW for the 2 hours preceding the Interruption Event and the Baseline Non-Interruptible Load multiplied by the duration of the Interruption Load in hours.

Interruptible Demand
Interruptible Demand shall be measured as the kW shown by or computed from the readings of the Company's demand meter for the highest 15-minute period during On-Peak as defined by Delivery Service Schedule 48 during the month, determined to the nearest kW, less the Baseline Non-Interruptible Load.

Baseline Non-Interruptible Load (N)
Once per calendar year, participants may nominate a Baseline Non-Interruptible Load in kW which shall not be subject to Interruption Events.

(continued)

Interruptible Service Term (N)

Unless otherwise removed from this schedule by the Company, participants shall agree to remain on Interruptible Service for a period of no less than 12 months. After terminating service under this schedule, a Consumer may not re-enroll for a 12 month period.

Special Conditions

1. If a participant does not interrupt its load by reducing its usage down to its Baseline Non-Interruptible Load or less during an Interruption Event, the participant shall be subject to the following penalties:
    a. For the first failure in a rolling 12 month period, the participant shall forfeit its Interruptible Demand Credit and Interruptible Energy Credit for the month in which it failed to interrupt.
    b. For the second failure in a rolling 12 month period, the participant shall forfeit its Interruptible Demand Credit and Interruptible Energy Credit for the month in which it failed to interrupt and for the prior six months.
    c. For the third failure in a rolling 12 month period, the participant shall be removed service on this schedule.
2. Participants removed from the schedule may not return to Interruptible Service for a period of 12 months.
3. Participants on this schedule may not also take service on Schedule 219 – Real-Time Day Ahead Pricing Pilot.
4. As a condition of receiving service on this schedule, the Company may elect to upgrade and/or update the Consumer's metering to record five minute interval data and otherwise be capable of being a participating resource in the Energy Imbalance Market. Any metering upgrade and/or update shall be at the Consumer's expense. The Company shall provide an estimate of the metering upgrade and/or update to the Consumer prior to incurring any expense.
5. Participants must nominate a Baseline Non-Interruptible Load that results in at least 1,000 kW of Interruptible Load.
6. At its sole discretion, the Company may elect to not provide service under this schedule or remove from participation Consumers with seasonal loads that do not correspond to the times of the year when anticipated Interruption Events may occur.
7. A Consumer may not enroll in this schedule for more than 10 MW of service.
8. A Consumer may not at the same time participate in this schedule and Schedule 219 or any other demand response program.

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.

(N)

(N)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Nonresidential Consumers receiving Delivery Service under Schedule 48, in conjunction with Supply Service Schedule 201. Participation will be limited to the first twenty-five (25) megawatts of load on a first come, first served basis.

Real-Time Day Ahead Energy Charges

Energy Charges under Supply Service Schedule 201 shall be calculated as the sum of Energy, in excess of Baseline Non-Real-Time Load, multiplied by the Real-Time Day Ahead Index price in each hour of the month multiplied by the Real-Time Day Ahead Adjustment Factor calculated for the month. Real-Time Day Ahead Energy Charges shall not be less than zero.

Real-Time Day Ahead Index

The Real-Time Day Ahead Index is comprised of the hourly prices for the day ahead market on the "ELAP_PACW-APND" node on the California Independent System Operator's Open Access Same-time Information System website.

Average Supply Service Schedule 201 Price for Schedule 48

Secondary Delivery Voltage, Per kWh	2.136¢
Primary Delivery Voltage, Per kWh	2.017¢
Transmission Delivery Voltage, Per kWh	1.896¢

Real-Time Day Ahead Adjustment Factor

For each monthly billing period, the Real-Time Day Ahead Adjustment Factor shall be calculated as the average price on the Real-Time Day Ahead Index for the month divided by the Average Supply Service Schedule 201 Price.

Administrative Fee

Participants shall pay a monthly administrative fee of $90.00.

Real-Time Day Ahead Demand Charges

The measurement of the On-Peak kW used to calculate Real-Time Day Ahead Demand Charges shall be the kW recorded by the meter during the highest 15-minute period during the 100 hours with the highest price on the Real-Time Day Ahead Index for the monthly billing period, determined to the nearest kW, less the Baseline Non-Real-Time Load. Baseline Non-Real-Time Load shall be subject to Demand Charges and will use the same measurement of On-Peak kW as other non-participating Consumers.

Baseline Non-Real-Time Load

Once per calendar year, participants may nominate a Baseline Non-Real-Time Load in kW which shall not be subject to Real-Time Day Ahead Pricing.

Real-Time Day Ahead Pricing Service Term

Participants shall agree to remain on Real-Time Day Ahead for a period of no less than 12 months. After terminating service under this schedule, a Consumer may not re-enroll for a 12 month period.

(N)

(continued)

Guarantee Payment (N)

The Company shall guarantee against an increase of Energy Charges for the first 12 months of enrollment in the program. If the total annual Energy Charges incurred on this Schedule exceed 10% over what costs would have been for the same period absent participation, the net difference, Guarantee Payment, will be credited on the Consumer's bill following the last month of the participant's one year anniversary of service on this schedule. The Administrative Fee shall not be included in the calculation of the Guarantee Payment and shall not be credited. No Guarantee Payment shall be given if the Consumer terminates service before the end of the initial one-year period.

Special Conditions

1. Participants on this schedule may not also take service on Schedule 218 – Interruptible Service Pilot.
2. Participants must nominate a Baseline Non-Real-Time Load that results in at least 1,000 kW of load subject to Real-Time Day Ahead Pricing.
3. A Consumer may not enroll in this schedule for more than 10 MW of service.
4. A Consumer may not at the same time participate in this schedule and Schedule 218 or any other demand response program.

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.

(N)

PACIFIC POWER
A DIVISION OF PACIFICORP

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Nonresidential Consumers who have elected to take this service. This service may be taken only in conjunction with the applicable Delivery Service Schedule.

Energy Charge

The Energy Charge shall be based on the Energy Charge Daily Rate as described below.

The Energy Charge Daily Rate is calculated by applying the same monthly weights produced by the Weighted Market Value calculation in the Transition Adjustment Schedule – Schedule 294 to actual daily market prices reported by the Platts indices at California/Oregon Border (COB), Mid-Columbia (Mid-C) and Desert Southwest (DSW), which includes the Palo Verde and Four Corners markets. The weights and thermal value will remain constant throughout the calendar year.

Standard Offer HLH

Market	Weight	
COB	11.24%	
DSW	16.90%	
Mid C	38.31%	
SP15	0.00%	
Thermal	33.55%	$17.96/MWh
Total	100%	

Standard Offer LLH

Market	Weight	
COB	5.86%	
DSW	8.30%	
Mid C	14.57%	
SP15	0.00%	
Thermal	71.27%	$18.94/MWh
Total	100%	

If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on-peak and off-peak prices shall be used to determine the price for the non-reported period. On-peak and off-peak hours shall be defined as reported by Platts for the Mid-Columbia Index. Currently, on-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-peak hours are all remaining hours.

(D)

The Consumer shall notify the Company of its choice of this option within the period defined in OAR 860-038-275. The Consumer shall remain on this option until the Company is properly notified of the Consumers' election of Direct Access Service. The Consumer may return to Cost-Based Supply Service consistent with the provisions of Schedule 201.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 230

EMERGENCY SUPPLY SERVICE

Available

In all territory served by the Company in the State of Oregon

Applicable

To Nonresidential Consumers. Service commences upon the Company becoming aware that the Nonresidential Consumer's ESS is no longer providing service. Delivery Service shall be billed under the Consumer's applicable rate schedule from the following: Schedule 23, 28, 30, (C) 41, 47, 48, 51, 53, 54. The Consumer must move off of this service within five business days of commencing service under this Schedule.

Energy Charge

The Energy Charge shall be based on the Energy Charge Daily Rate as described below.
The Energy Charge Daily Rate is the Platts Mid-Columbia Daily Electricity Firm Price Index (Platts-Mid-C Index) plus the Emergency Default Risk Premium plus the adjustment for losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on-peak and off-peak prices shall be used to determine the price for the non-reported period.

On-peak and off-peak hours shall be defined as reported by Platts for the Mid-Columbia Index. Currently, on-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-peak hours are all remaining hours. (D)

The Emergency Default Risk Premium shall be 25 percent of the Platts-Mid-C Index.

The loss adjustment shall be included by multiplying the Energy Charge Daily Rate by the following adjustment factors:

Transmission Delivery Voltage	1.04527
Primary Delivery Voltage	1.06904
Secondary Delivery Voltage	1.10006

In addition to this energy charge, all customers purchasing this service are required to pay for ancillary services at the rates determined by the appropriate pro forma transmission tariffs.

Energy Needs Forecast (continued) (D)

Consumer may request both Standard Blocks and Non-Standard Blocks of Energy in an ENF.

Daily ENF
Prior to HE 0615 PPT on the Pre-schedule Day, Consumer shall provide to Company Consumer's ENF specifying daily preschedule quantities by hour in equal volume blocks. By HE 0630 PPT on the Pre-schedule Day, Company shall notify Consumer of its acceptance of Consumer's ENF or modifications to Consumer's ENF. If Company has modified Consumer's ENF, by HE 0645 PPT on the Pre-schedule Day, Consumer shall notify Company of its acceptance of the modified ENF. Acceptance by Company of Consumer's ENF or acceptance by Consumer of Company's modification of Consumer's ENF shall constitute an ERPA (described below).

Unless modified pursuant to the Western Electricity Coordinating Council (WECC) Interchange Scheduling and Accounting Subcommittee (ISAS) Pre-scheduling Calendar, "Pre-schedule Day" means the business day immediately preceding the day of delivery unless the day of delivery is Sunday or Monday, in which case the Pre-schedule Day shall be the immediately preceding Friday, or unless the day of delivery is Saturday, the Pre-schedule Day shall be the immediately preceding Thursday. In the event the Pre-schedule Day falls on a NERC-defined holiday, the pre-schedule requirement shall be adjusted to reflect such holiday.

Monthly or Quarterly ENF
Between 0900 and 1159 PPT during the last day of gas bid week (Annually, Company will provide participating Consumers with a twelve month calendar of gas bid week days), Consumer shall contact the Company at a designated telephone number and receive a Mid Columbia market price quoted by a broker for the ENF. During that telephone call, the Consumer may purchase the HLH, LLH or Flat block of monthly or quarterly energy at a volume agreed to by Company and Consumer and at the price quoted. Unless accepted by Consumer during the telephone call, the price quoted shall expire at the end of the telephone call. Acceptance by Consumer of the price quoted shall constitute an ERPA (described below).

Broker quote. A Broker quote is a price quote from a brokering house or trading platform that the Company is utilizing on a given day.

Economic Replacement Power Agreement

The Economic Replacement Power Agreement (ERPA) specifies Electricity supplied by Company and agreed to by Consumer to meet in whole or in part an Energy Needs Forecast (ENF). An ERPA shall be required for transactions covered by an ENF. The Consumer shall use best efforts to conform actual Energy usage to the ERPA. If Consumer cannot take ERP as agreed to in an ERPA, Consumer shall promptly notify Company of the same. Such notice shall include, where applicable, the time when the shutdown occurred or is expected to occur and the anticipated duration of such shutdown and any other arrangements as represented in the written agreement.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To New Large Load for Nonresidential Consumers taking Delivery Service under Schedule 848 who have chosen to opt-out of the Company's Cost-Based Supply Service prior to the inception of electric service to the New Large Load. Consumer must officially notify the Company of its election for this program in accordance with Rule 22 of this tariff. New Large Load must be separately metered or have its usage measured based on a determination that has comparable accuracy and is mutually agreeable between the Company and the Consumer.

Total Eligible Load

A total of 89 aMW will be accepted under this program unless the Commission determines otherwise.

Administration Fee

Consumers taking service under this program will pay the following program Administration Fee:
$400 per month

Fixed Generation Transition Adjustment

A transition adjustment of 20 percent of fixed generation rates will be charged for the first five years of service to the Consumer under this program beginning when the Consumer's electric service is first energized. Fixed generation rates include Schedule 200, Base Supply Service rates along with any other rates which collect non-net power cost generation costs that are in effect during the five year transition period for each Consumer. The adjustment will be applied at 20 percent of the rates included in the Company's effective tariffs applicable to Delivery Service Schedule 48. At the end of the applicable five-year period, Consumers who have elected this option will no longer be subject to the fixed generation transition adjustment.

List of effective schedules with fixed generation rates which will incur a 20 percent Fixed Generation Transition Adjustment:
Schedule 200, Base Supply Service (D)
Schedule 197, Generation Plant Removal Adjustment (N)
Schedule 203, Renewable Resource Deferral Adjustment
Schedule 204, Oregon Solar Incentive Program Deferral
Schedule 205, TAM Adjustment for Other Revenues
Schedule 207, Community Solar Start-Up Cost Recovery Adjustment

Existing Load Shortage Transition Adjustment

The Existing Load Shortage Transition Adjustment will be applied to the Existing Load Shortage of the Consumer and for the Existing Load Shortage for all of the Consumer's affiliated Consumers. An affiliated Consumer is a Consumer for which a controlling interest is held by another Consumer who is engaged in the same line of business as the holder of the controlling interest. Existing Load Shortage means the larger of zero or a Consumer's Average Historical Cost-of-Service Load plus Incremental Demand-Side Management less the average Cost-of-Service Eligible load during the previous 60 months. Average Historical Cost-of-Service Load means the average monthly Cost-of-Service Eligible Load during the 60 month period beginning five years prior to the date the Consumer gives binding notice of participation in this program.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 297

Energy Conservation Charge

The applicable adjustment rates are listed below by Delivery Service Schedule.

Schedule	Adjustment Rate	
4	0.346 cents per kWh	
5	0.346 cents per kWh	
15	0.453 cents per kWh	
23, 723	0.343 cents per kWh	
28, 728	0.278 cents per kWh	
30, 730	0.245 cents per kWh	
41, 741	0.332 cents per kWh	
47, 747	0.206 cents per kWh	
48, 748	0.206 cents per kWh	(D)
51, 751	0.631 cents per kWh	
53, 753	0.224 cents per kWh	(D)
54, 754	0.293 cents per kWh	

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 299

RATE MITIGATION ADJUSTMENT

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No. 36 shall have applied an amount equal to the product of all metered kilowatt-hours multiplied by the following cents per kilowatt hour.

	Secondary	Primary	Transmission	
Schedule 4	0.000¢			(C)
Schedule 5	0.000¢			
Schedule 15	0.000¢			
Schedule 23, 723	0.000¢	0.000¢		
Schedule 28, 728	0.282¢	0.282¢		
Schedule 30, 730	0.066¢	0.066¢		
Schedule 41, 741	(0.544¢)	(0.544¢)		
Schedule 47, 747	(0.134¢)	(0.168¢)	(0.207¢)	
Schedule 48, 748	(0.134¢)	(0.168¢)	(0.207¢)	(C) (D)
Schedule 51, 751	0.000¢			(C) (D)
Schedule 53, 753	0.000¢			(C)
Schedule 54, 754	0.000¢			(C)

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. (C)

Distribution Charge	**Delivery Voltage** Secondary	Primary	
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	$ 1.50	$ 1.50	(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	$ 5.08	$ 4.94	(I)
Distribution Energy Charge, per kWh	3.640¢	3.537¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.078¢	0.076¢	(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of Company's demand meter for the 15-minute period of Consumer's greatest use during the month, determined to the nearest kW.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 728

GENERAL SERVICE
LARGE NONRESIDENTIAL 31 KW TO 200 KW
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90. (C)

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤ 50 kW, per month	$ 21.00	$ 29.00	(I)
Load Size 51-100 kW, per month	$ 39.00	$ 49.00	
Load Size 101 - 300 kW, per month	$ 93.00	$115.00	
Load Size > 300 kW, per month	$132.00	$164.00	
Load Size Charge			
≤ 50 kW, per kW Load Size	$ 1.30	$ 1.60	
51-100 kW, per kW Load Size	$ 1.05	$ 1.30	
101 – 300 kW, per kW Load Size	$ 0.65	$ 0.80	
> 300 kW, per kW Load Size	$ 0.40	$ 0.40	
Demand Charge, per kW	$ 4.45	$ 5.62	
Distribution Energy Charge, per kWh	0.450¢	0.089¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.086¢	0.080¢	(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 730

GENERAL SERVICE
LARGE NONRESIDENTIAL 201 KW TO 999 KW
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90. (C)

<u>**Distribution Charge**</u>	<u>**Delivery Voltage**</u>		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤ 200 kW, per month	$541.00	$538.00	(I)
Load Size 201 - 300 kW, per month	$161.00	$168.00	
Load Size > 300 kW, per month	$423.00	$437.00	(I)
Load Size Charge			
≤ 200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$ 1.90	$ 1.85	(I)
> 300 kW, per kW Load Size	$ 0.95	$ 0.90	(I)
Demand Charge, per kW	$ 4.64	$ 4.64	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
<u>**System Usage Charge**</u>			
Schedule 200 Related, per kWh	0.082¢	0.081¢	(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of Company's demand meter for the 15-minute period of Consumer's greatest use during the month, determined to the nearest kW, but not less than 100 kW.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

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. (C) (C)

<u>Distribution Charge</u>	<u>Delivery Voltage</u> Secondary	Primary	
Basic Charge (November billing only)			
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$ 390.00	$ 380.00	(I)
Three Phase Load Size > 300 kW	$1,530.00	$1,490.00	
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$ 19.00	$ 18.00	
Three Phase 51 - 300 kW, per kW Load Size	$ 13.00	$ 13.00	
Three Phase > 300 kW, per kW Load Size	$ 8.00	$ 8.00	
Single Phase, Minimum Charge	$ 70.00	$ 70.00	
Three Phase, Minimum Charge	$ 115.00	$ 110.00	
Distribution Energy Charge, per kWh	4.464¢	4.338¢	(I)
Reactive Power Charge, per kVar	$ 0.65	$ 0.60	
<u>System Usage Charge</u>			
Schedule 200 Related, per kWh	0.074¢	0.072¢	

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of Company's meter, or by appropriate test, for the 15-minute period of Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

If Motor Size Is:	**Monthly kW is:**
2 hp or less	2 kW
Over 2 through 3 hp	3 kW
Over 3 through 5 hp	5 kW
Over 5 through 7.5 hp	7 kW
Over 7.5 through 10 hp	9 kW

(continued)

On-Peak Period

The kWh shown by or computed from the readings of the Company's energy meter during on-peak hours. The on-peak period is
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.

Off-Peak Period

All non On-Peak Period plus the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. (D)

Seasonal Definition

Winter months are defined as November 1 through March 31. Summer months are defined as April 1 through October 31.

Special Conditions

1. At the option of the Consumer, service may be provided under the otherwise applicable General Service Schedule.
2. The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs. The sale of electricity for fuel to a motor vehicle is expressly allowed as described in rule 2.E of this tariff.
3. A DC Fast Charger is defined for the purposes of eligibility on this rate schedule as a charging station with a Direct Current (DC) connection that has been designed to recharge the battery of an electric vehicle.
4. An electric vehicle charging site is considered to be broadly available to the general publicly for the purposes of eligibility on this rate schedule if it is available for use by any driver and is capable of charging more than one make of automobile. Eligibility and acceptance of a customer for service under this rate schedule is subject to review and approval by the Company.
5. Prior to receiving service under this rate schedule, the Consumer must disclose to the Company the number of chargers to be installed at the station, the type and capacity of each charger installed, and the maximum number of vehicles that can simultaneously use the station to recharge batteries.
6. The company reserves the right to terminate service under this schedule if it finds that excessive fees imposed by the charging station owner result in the charging station not being broadly available, per the requirements of this schedule.

(continued)

Issued February 14, 2020
Etta Lockey, Vice President, Regulation
Effective for service on and after January 1, 2021
Docket No. UE 374

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 747

LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS 1,000 KW AND OVER
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Reserves Charges, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90. (C)

	Delivery Voltage			
Distribution Charge	**Secondary**	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$640.00	$610.00	$820.00	(I) (I) (R)
Facility Capacity > 4,000 kW, per month	$1,220.00	$1,100.00	$1,520.00	(I) (I) (R)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$2.70	$1.20	$1.25	(I) (R) (R)
> 4,000 kW, per kW Facility Capacity	$2.60	$1.10	$1.25	(I) (R) (R)
On-Peak Demand Charge, per kW	$4.68	$4.83	$3.48	(I) (I) (R)
Reactive Power Charges				
Per kVar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Reserves Charges				
Spinning Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company-approved Self-Supply Agreement)				
per kW of Self-Supplied Spinning Reserves	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves (with Company-approved load reduction plan or Self-Supply Agreement)				
per kW of approved load reduction kW	($0.27)	($0.27)	($0.27)	
System Usage Charge				
Schedule 200 Related, per kWh	0.076¢	0.075¢	0.073¢	(I) (I) (I)

(continued)

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. Summer On-Peak hours are from 1 p.m. to 11 p.m. all days in the Summer months of July, August and September. Non-Summer On-Peak hours are from 5 a.m. to 9 a.m. and 4 p.m. to 12 a.m. (midnight) in the Non-Summer months of October through June. All remaining hours are Off-Peak. (C)

Metering Adjustment (D)

A Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718.

A Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290.

Baseline Demand

The kW of Demand supplied by the Company to the Large Nonresidential Consumer when the Consumer's generator is regularly operating as planned by the Consumer. For new Partial Requirements Consumers, the Consumer's peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations, shall be used to calculate the Baseline Demand. Existing Partial Requirements Consumers shall select their Baseline Demand for each contract term based upon the Consumer's peak demand for the most recent 12 months during the times the generator was operating as planned, adjusted for changes in load and planned generator operations. Planned generator operations includes changes in the electricity produced by the generator as well as the Consumer's plans to sell any electricity produced by the generator to the Company or third parties. Any modification to the Baseline Demand must be consistent with Special Conditions in this schedule.

Facility Capacity

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, but shall not be less than the Consumer's Baseline Demand. For new customers during the first three months of service under this schedule, the Facility Capacity will be equal to the Consumer's Baseline Demand.

Reserves Charges

The Company provides Reserves for the Consumer's Facility Capacity. Reserves consist of the following components:

Spinning Reserves

In addition to the Spinning Reserves provided for the Consumer's Baseline Demand, Spinning Reserves provide Electricity immediately after a Consumer's demand rises above Baseline Demand.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS, to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until Consumer fails to meet or exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 747.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		**Delivery Voltage**		
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$640.00	$610.00	$820.00	(I) (I) (R)
Facility Capacity > 4000 kW, per month	$1,220.00	$1,100.00	$1,520.00	(I) (I) (R)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$2.70	$1.20	$1.25	(I) (R) (R)
> 4000 kW, per kW Facility Capacity	$2.60	$1.10	$1.25	(I) (R) (R)
On-Peak Demand Charge, per kW	$4.68	$4.83	$3.48	(I) (I) (R)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
System Usage Charge				
Schedule 200 Related, per kWh	0.076¢	0.075¢	0.073¢	(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)

Issued February 14, 2020 — **Effective for service on and after January 1, 2021**
Etta Lockey, Vice President, Regulation — *Docket No. UE 374*

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.

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. Summer On-Peak hours are from 1 p.m. to 11 p.m. all days in the Summer months of July, August and September. Non-Summer On-Peak hours are from 5 a.m. to 9 a.m. and 4 (C) p.m. to 12 a.m. (midnight) in the Non-Summer months of October through June. All remaining hours are Off-Peak. (D)

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718.

For a consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290.

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 not resell electric service received from Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs.

Term of Contract

Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

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.

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. (C)

(C)

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	$ 7.11	$ 7.54	$ 7.67	$ 7.78	$ 8.26	$ 10.08
Functional Lighting - Customer Funded Conversion	$ 3.73	$ 3.93	$ 4.05	$ 4.12	$ 4.41	$ 5.38
Decorative Series	N/A	$ 13.23	$ 13.33	N/A	N/A	N/A

(C)
(D)
(N)

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.

(N)

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this Schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, and distribution charges are collected through rates in this schedule.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

STREET LIGHTING SERVICE
COMPANY-OWNED SYSTEM - NO NEW SERVICE
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company (except Multnomah County) in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To service furnished by means of Company-owned installations, for the lighting of public streets, highways, alleys and parks under conditions and for street lights of sizes and types not specified on other schedules of this Tariff. Company may not be required to furnish service hereunder to other than municipal Consumers. This schedule is closed to new service beginning November 8, 2006.

Monthly Billing

For systems owned, operated and maintained by Company. The Monthly Billing shall be the Rate Per kWh below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

A flat rate equal to one-twelfth of Company's estimated annual cost for operation, maintenance, fixed charges and depreciation applicable to the street lighting system, including energy costs as follows:

For dusk to dawn operation, per kWh	1.551¢
For dusk to midnight operation, per kWh	1.849¢

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.

Term of Contract

Not less than five years for service to an overhead, or ten years to an underground, Company-owned system by written contract when unusual conditions prevail.

Provisions

1. Installation, daily operation, repair and maintenance of lights on this rate schedule will be performed by the Company, providing that the facilities furnished remain readily accessible for maintenance purposes.
2. Inoperable lights will be repaired as soon as reasonably possible, during regular business hours or as allowed by Company's operating schedule and requirements, provided the Company receives notification of inoperable lights from Consumer or a member of the public by either notifying Pacific Power's customer service (1-888-221-7070) or www.pacificpower.net/streetlights. Pacific Power's obligation to repair street lights is limited to this tariff.
3. Existing fixtures and facilities that are deemed irreparable will be replaced with comparable high pressure sodium vapor fixtures and facilities from the Company's Construction Standards.

(continued)

Provisions (continued)

4. The Company will, upon written request of Consumer, convert existing streetlighting facilities to other types of Company approved facilities. In such event, should the revenue increase, the streetlighting extension allowance defined in Rule 13 Section III.F is applicable only to the increase in annual revenue due to the replacement. If there is no increase in revenue, there is no allowance, The Consumer shall advance the estimated cost of all materials and labor associated with installation and removal, less the estimated salvage on the removed facilities, in excess of the applicable allowance.
5. Temporary disconnection and subsequent reconnection of electrical service requested by the Consumer shall be at the Consumer's expense. The Consumer may request temporary suspension of power by written notice. During such periods, the monthly rate will be reduced by the company's estimated average energy costs for the luminaire. The facilities may be considered idle and may be removed after 12 months of inactivity. The Company will not be required to re-establish such service under this rate schedule if service has been permanently discontinued by the Consumer.
6. Pole re-painting, when requested by the Consumer and not required for safety reasons, shall be done at Consumer's expense using the original pole color.
7. Glare and vandalism shielding, when requested by the Consumer, shall be installed at the Consumer's expense. In cases of repetitive vandalism, the Company may notify the Consumer of the need to install vandal shields at the Consumer's expense, or otherwise have the lighting removed.

Termination of Service

The Consumer can request removal of lights with minimum of 2 month's written notice. The Consumer will be charged with the costs of removal.

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.

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. (C)

High Pressure Sodium Vapor						
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000
Watts	70	100	150	200	250	400
Monthly kWh	31	44	64	85	115	176
Energy Only Service	$ 1.45	$ 2.06	$ 2.99	$ 3.98	$ 5.38	$ 8.24

(I)

Metal Halide					
Lumen Rating	9,000	12,000	19,500	32,000	107,800
Watts	100	175	250	400	1,000
Monthly kWh	39	68	94	149	354
Energy Only Service	$ 1.82	$ 3.18	$ 4.40	$ 6.97	$ 16.56

(I)

For non-listed luminaires the cost will be calculated for 4167 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire	¢/kWh
Energy Only Service	4.679

(I)

Maintenance Service (No New Service)

Where the utility operates and maintains the system, a flat rate equal to one-twelfth the estimated annual cost for operation and maintenance will be added to the Energy Only Service rates listed above. Monthly Maintenance is only applicable for existing monthly maintenance service agreements in effect prior to May 24, 2006.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 754

RECREATIONAL FIELD LIGHTING - RESTRICTED
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise which is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At Consumer's option, service for recreational field lighting may be taken under Company's applicable General Service Schedule.

Monthly Billing

The Monthly Billing shall be the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90. (C)

Distribution Charge

Basic Charge, Single Phase, per month	$ 6.00	
Basic Charge, Three Phase, per month	$ 9.00	
Distribution Energy Charge, per kWh	5.287¢	(I)

System Usage Charge

Schedule 200 Related, per kWh	0.020¢	(R)

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

Special Conditions

Consumer shall own all poles, wire and other distribution facilities beyond the Company's point of delivery.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

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: (C)

	Delivery Voltage			
	Secondary	Primary	Transmission	
Daily ERS Demand Charge				
per kW of Daily ERS On-Peak Demand	$0.182	$0.188	$0.136	(I)(I)(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)

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS and are participating in the New Large Load Direct Access Program in Schedule 293 or to existing consumers who have completed the five-year transition period for the Five-Year Cost of Service Opt-Out in Schedule 296. Existing consumers who have completed the five-year transition period for the Five-Year Cost of Service Opt-Out in Schedule 296 must have electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until Consumer fails to meet or exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the Distribution Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		**Delivery Voltage**		
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$640.00	$610.00	$820.00	(I) (I) (R)
Facility Capacity > 4000 kW, per month	$1,220.00	$1,100.00	$1,520.00	(I) (I) (R)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$2.70	$1.20	$1.25	(I) (R) (R)
> 4000 kW, per kW Facility Capacity	$2.60	$1.10	$1.25	(I) (R) (R)
On-Peak Demand Charge, per kW	$4.68	$4.83	$3.48	(I) (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)

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.

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. Summer On-Peak hours are from 1 p.m. to 11 p.m. all days in the Summer (C)
months of July, August and September. Non-Summer On-Peak hours are from 5 a.m. to 9 a.m. and 4 p.m. to 12 a.m. (midnight) in the Non-Summer months of October through June. All remaining hours are Off-Peak. (D)

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718.

For a consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290.

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 distribution charges are collected through distribution charges.

Special Conditions

Consumer shall not resell electric service received from Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs.

Term of Contract

Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

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.

Definitions (continued)

Emergency Default Service: Has the meaning described in Rule 2, "Types of Service."

Emergency Distribution Service: Service in supply to, or made available to, load devices which are operated only in emergency situations or in testing for same. Such service contemplates frequency and intensity of operation reflective of emergency conditions and excludes service to freeze protection devices which operate in the coldest period of the year.

Energy: Electric energy, measured in kilowatt-hours.

Extension: A branch from, continuation of, or an increase in the capacity of an existing Company-owned transmission or distribution line. An extension may be either single-phase or three-phase or a conversion from a single-phase line to a three-phase line. An extension may also be the addition of, or increase in the capacity of other facilities.

Intermittent Service: Continuously available service which the Consumer uses intermittently and in such duration that minimal amounts of electric power or energy are registered by Company meters for such uses.

Kilovar (kvar): A unit of reactive power equal to 1,000 reactive volt-amperes.

Kilovar-hour (Kvarh): The amount of reactive flow in one hour, at a constant rate of one kilovar.

Kilowatt (kW): A unit of power equal to 1,000 watts.

Kilowatt-hour (kWh): The amount of energy delivered in one hour, when delivery is at a constant rate of one kilowatt.

Large Nonresidential Consumer: A Nonresidential Consumer that is not a Small Nonresidential Consumer.

Load: The amount of electricity delivered to or required by a Consumer.

Multi-Family Home: A residential building that contains three or more dwelling units. (N)

NAICS Code: North American Industry Classification System Code.

New Large Load: as defined in OAR 860-038-0710, load associated with a new facility, an existing facility or an expansion of an existing facility, which: has never been contracted for or committed to in writing by a cost-of-service Consumer with an electric company, and is expected to result in a 10 average megawatt (aMW) or more increase in the Consumer's power requirements during the first three years after new operations begin.

Nonresidential Consumer: A retail electricity consumer that is not a Residential Consumer.

Paralleling: Connection by a Consumer of any source of electric power to Company's system or to a Consumer's system which is connected to Company's system.

(continued)

Definitions (continued)

Service Options: Optional services that are part of Direct Access Service. Service Options include Billing Services and the purchase of Ancillary Services. Service Options do not include Service Elections or the choice of ESS.

Service of Questionable Permanency: Service for operations of a speculative character or the permanency of which has not been established. This will include, among others, service to mines, logging or associated woods operations, rock crushers or paving plants.

Single Enterprises: A separate business or other individual activity carried on by a Consumer. The term does not apply to associations or combinations of Consumers.

Single-Family Home: A residential building that contains less than three dwelling units. (N)

Small Nonresidential Consumer: A Nonresidential Consumer whose demand has not exceeded 30 kW more than once within the preceding 13 months or with seven months or less of service whose demand has not exceeded 30 kW.

Standard Offer Service: Has the meaning described in Rule 2, “Types of Service.”

Standby Service: Service in supply to, or made available to, load which is served part or all of the time by another power source for reasons of increased reliability of supply through duplication of source.

Supplementary Service: Service in supply to, or made available to, load which receives some degree of simultaneous supply from another power source for additional supply or greater economy of supply at peak or light load conditions.

Tract or Subdivision: An area for dwellings which may be identified by filed subdivision plans or as an area in which a group of dwellings may be constructed about the same time, either by a large scale builder or by several builders working on a coordinated basis.

Utility: Pacific Power

Docket No. UE 374
Exhibit PAC/1402
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Unbundled Results of Operations - Summary and Detail

February 2020

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2021 Forecast

Function			Revenue Requirement
Production		$	730,302,291
Transmission		$	217,545,364
Distribution		$	312,035,932
Distribution-Lighting		$	3,664,768
Distribution Total		$	315,700,700
Ancillary		$	24,876,786
Customer Billing		$	10,872,685
Customer Metering		$	26,593,383
Customer Other		$	11,776,151
Retail Service	a	$	-
Public Purposes	b	$	-
Total State of Oregon		$	1,337,667,360

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, 2021 Forecast

										Customer			Distribution Components		
		ROR	ROE	Total $	Production	Transmission	Distribution	Distribution-Lighting	Ancillary	Billing	Metering	Other	Poles & Wires	Poles & Wires-Lighting	Franchise Fees
1	Functionalized Situs Revenues @ Earned	7.18%	9.26%	1,308,884,715	719,611,917	208,934,852	303,399,015	3,554,826	24,876,786	10,791,648	25,971,018	11,744,653	270,870,224	3,173,697	32,909,920
2	System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-
3	Total Oregon General Business Revenue			1,308,884,715	719,611,917	208,934,852	303,399,015	3,554,826	24,876,786	10,791,648	25,971,018	11,744,653	270,870,224	3,173,697	32,909,920
4															
5	Target Increase in Return	7.68%	10.20%	20,997,497	7,988,291	6,434,132	5,950,183	75,742	-	60,554	465,057	23,537	5,950,183	75,742	-
6															
7	Add														
8	Uncollectible Expense			110,860	41,175	33,165	33,266	423	-	312	2,397	121	30,670	390	2,629
9	Franchise Tax			676,392			667,890	8,502							676,392
10	Other Revenue Based Taxes			152,203	56,531	45,532	45,672	581	-	429	3,291	167	42,108	536	3,610
11	Inc Taxes - State			1,264,081	480,907	387,344	358,210	4,560	-	3,645	27,997	1,417	358,210	4,560	-
12	Inc Taxes - Federal			5,581,613	2,123,470	1,710,339	1,581,694	20,134	-	16,097	123,623	6,257	1,581,694	20,134	-
13	Total Increase Needed			28,782,645	10,690,374	8,610,512	8,636,916	109,942	-	81,037	622,365	31,498	7,962,865	101,362	682,631
14															
15	Total Oregon General Business Revenue @	7.68%	10.20%	1,337,667,361	730,302,291	217,545,364	312,035,932	3,664,768	24,876,786	10,872,685	26,593,383	11,776,151	278,833,090	3,275,059	33,592,551
16	Less: System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-
17	Total Unbundled Revenue Requirement			1,337,667,361	730,302,291	217,545,364	312,035,932	3,664,768	24,876,786	10,872,685	26,593,383	11,776,151	278,833,090	3,275,059	33,592,551
18															
19	Rate Base			4,194,704,290	1,595,834,026	1,285,357,003	1,188,677,897	15,131,073	-	12,097,035	92,905,245	4,702,011	1,188,677,897	15,131,073	-
					38.04%	30.64%	28.34%	0.36%	0.00%	0.29%	2.21%	0.11%	28.34%	0.36%	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 374
Exhibit PAC/1403
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Functionalized Oregon Results of Operations Report

February 2020

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Unbundled Results of Operations
12 Months Ended December 31, 2021 Forecast

	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Other
Operating Revenues									
General Business Revenues	1,308,884,715	719,611,917	208,934,852	303,399,015	3,554,826	24,876,786	10,791,648	25,971,018	11,744,653
Special Sales	73,285,143	73,285,143	-	-	-	-	-	-	-
Other Operating Revenues	50,008,283	31,056,054	33,502,285	4,983,251	1,777	(24,876,786)	4,716,096	280,440	345,166
Total Operating Revenues	1,432,178,141	823,953,114	242,437,137	308,382,266	3,556,603	-	15,507,744	26,251,458	12,089,819
Operating Expenses									
Steam Production	247,310,378	247,310,378	-	-	-	-	-	-	-
Nuclear Production	-	-	-	-	-	-	-	-	-
Hydro Production	11,814,928	11,814,928	-	-	-	-	-	-	-
Other Power Supply	257,424,578	257,424,578	-	-	-	-	-	-	-
ECD	-	-	-	-	-	-	-	-	-
Transmission	56,016,262	229,803	55,786,458	-	-	-	-	-	-
Distribution	69,726,150	-	-	67,580,518	980,178	-	-	1,165,454	-
Customer Accounts	30,202,104	2,912,507	856,966	1,090,069	12,572	-	10,180,568	9,712,615	5,436,807
Customer Service	6,141,331	-	-	2,317,803	-	-	-	-	3,823,527
Sales	-	-	-	-	-	-	-	-	-
Administrative & General	41,472,852	9,925,526	4,643,647	23,480,558	108,103	-	1,046,437	1,597,640	670,940
Total O & M Expenses	720,108,582	529,617,720	61,287,072	94,468,948	1,100,853	-	11,227,005	12,475,709	9,931,275
Depreciation	316,560,184	210,710,926	40,743,555	59,956,035	909,414	-	440,186	3,552,265	247,802
Amortization Expense	21,091,819	15,660,534	1,408,283	75,402	4,113	-	1,705,932	997,618	1,239,937
Taxes Other Than Income	86,353,112	24,468,193	12,247,519	48,128,199	197,868	-	270,561	849,832	190,940
Income Taxes - Federal	(10,587,018)	(53,686,153)	19,908,228	20,602,143	448,691	-	555,180	1,695,061	(110,168)
Income Taxes - State	8,640,100	(1,120,662)	4,508,663	4,665,815	101,616	-	125,733	383,884	(24,950)
Income Taxes - Def Net	(11,537,533)	(16,053,758)	10,127,981	(5,543,132)	(291,722)	-	315,092	(369,571)	277,578
Investment Tax Credit Adj.	-	-	-	-	-	-	-	-	-
Misc Revenue & Expense	546,879	(156,945)	(28,329)	732,153	-	-	-	-	-
Total Operating Expenses	1,131,176,126	709,439,856	150,202,972	223,085,564	2,470,833	-	14,639,689	19,584,798	11,752,413
Operating Revenue for Return	301,002,015	114,513,259	92,234,165	85,296,702	1,085,770	-	868,055	6,666,660	337,405
Rate Base									
Electric Plant in Service	8,433,754,519	3,726,159,697	1,995,748,561	2,476,971,708	32,387,389	-	40,013,011	134,696,106	27,778,047
Plant Held for Future Use	-	1,629,231	(203,406)	(1,332,831)	-	-	(47,167)	(45,826)	-
Misc Deferred Debits	67,302,496	57,707,003	3,930,538	640,468	48,763	-	4,113,659	554,375	307,691
Elec Plant Acq Adj	1,749,820	1,749,820	-	-	-	-	-	-	-
Nuclear Fuel	-	-	-	-	-	-	-	-	-
Prepayments	8,805,023	3,720,883	846,972	2,943,471	47,093	-	416,460	534,023	296,121
Fuel Stock	42,986,611	42,986,611	-	-	-	-	-	-	-
Material & Supplies	73,659,471	61,159,021	756,777	11,353,316	-	-	-	390,357	-
Working Capital	8,091,631	(922,939)	1,721,300	5,290,816	76,685	-	639,984	818,003	467,782
Weatherization Loans	(1,363)	-	-	(1,363)	-	-	-	-	-
Miscellaneous Rate Base	-	-	-	-	-	-	-	-	-
Total Electric Plant	8,636,348,208	3,894,189,327	2,002,800,742	2,495,865,585	32,559,929	-	45,135,946	136,947,038	28,849,641
Rate Base Deductions									
Accum Prov For Depr	(3,200,067,136)	(1,498,869,341)	(521,895,028)	(1,143,336,204)	(15,131,118)	-	(2,581,893)	(16,791,374)	(1,462,178)
Accum Prov For Amort	(190,276,927)	(64,300,891)	(18,701,915)	(42,585,267)	(668,497)	-	(26,524,322)	(18,250,338)	(19,245,696)
Accum Def Income Taxes	(591,816,891)	(317,382,398)	(162,120,673)	(101,860,890)	(1,326,533)	-	(1,550,121)	(5,830,655)	(1,745,621)
Unamortized ITC	0	0	0	0	0	-	0	0	0
Customer Adv for Const	(13,802,322)	-	(11,162,027)	(2,497,147)	(32,383)	-	-	(110,766)	-
Customer Service Deposits	-	-	-	-	-	-	-	-	-
Misc. Rate Base Deductions	(445,680,643)	(417,802,670)	(3,564,096)	(16,908,180)	(270,326)	-	(2,382,574)	(3,058,661)	(1,694,135)
Total Rate Base Deductions	(4,441,643,918)	(2,298,355,301)	(717,443,739)	(1,307,187,688)	(17,428,857)	-	(33,038,911)	(44,041,793)	(24,147,630)
Total Rate Base	4,194,704,290	1,595,834,026	1,285,357,003	1,188,677,897	15,131,073	-	12,097,035	92,905,245	4,702,011
Return on Rate Base	7.1758%	7.1758%	7.1758%	7.1758%	7.1758%	7.1758%	7.1758%	7.1758%	7.1758%
Return on Equity	9.2647%	9.2647%	9.2647%	9.2647%	9.2647%	9.2647%	9.2647%	9.2647%	9.2647%

2020 PROTOCOL
RESULTS OF OPERATIONS SUMMARY
12 Months Ended December 31, 2021 Forecast

		Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
Operating Revenues											
	General Business Revenues	1,308,884,715	719,611,917	208,934,852	303,399,015	3,554,826	24,876,786	10,791,648	25,971,018	11,744,653	-
	General Business Revenues	-	-	-	-	-	-	-	-	-	-
	Interdepartmental	-	-	-	-	-	-	-	-	-	-
	Special Sales	73,285,143	73,285,143	-	-	-	-	-	-	-	-
	Other Operating Revenues	50,008,283	31,056,054	33,502,285	4,983,251	1,777	(24,876,786)	4,716,096	280,440	345,166	-
	Total Operating Revenues	1,432,178,141	823,953,114	242,437,137	308,382,266	3,556,603	-	15,507,744	26,251,458	12,089,819	-
Operating Expenses											
	Steam Production	247,310,378	247,310,378	-	-	-	-	-	-	-	-
Operating Expenses	Nuclear Production	-	-	-	-	-	-	-	-	-	-
	Hydro Production	11,814,928	11,814,928	-	-	-	-	-	-	-	-
	Other Power Supply	257,424,578	257,424,578	-	-	-	-	-	-	-	-
	ECD	-	-	-	-	-	-	-	-	-	-
	Transmission	56,016,262	229,803	55,786,458	-	-	-	-	-	-	-
	Distribution	69,726,150	-	-	67,580,518	980,178	-	-	1,165,454	-	-
	Customer Accounts	30,202,104	2,912,507	856,966	1,090,069	12,572	-	10,180,568	9,712,615	5,436,807	-
	Customer Service	6,141,331	-	-	2,317,803	-	-	-	-	3,823,527	-
	Sales	-	-	-	-	-	-	-	-	-	-
	Administrative & General	41,472,852	9,925,526	4,643,647	23,480,558	108,103	-	1,046,437	1,597,640	670,940	-
	Total O & M Expenses	720,108,582	529,617,720	61,287,072	94,468,948	1,100,853	-	11,227,005	12,475,709	9,931,275	-
	Depreciation	316,560,184	210,710,926	40,743,555	59,956,035	909,414	-	440,186	3,552,265	247,802	-
	Amortization Expense	21,091,819	15,660,534	1,408,283	75,402	4,113	-	1,705,932	997,618	1,239,937	-
	Taxes Other Than Income	86,353,112	24,468,193	12,247,519	48,128,199	197,868	-	270,561	849,832	190,940	-
	Income Taxes - Federal	(10,587,018)	(53,686,153)	19,908,228	20,602,143	448,691	-	555,180	1,695,061	(110,168)	-
	Income Taxes - State	8,640,100	(1,120,662)	4,508,663	4,665,815	101,616	-	125,733	383,884	(24,950)	-
	Income Taxes - Def Net	(11,537,533)	(16,053,758)	10,127,981	(5,543,132)	(291,722)	-	315,092	(369,571)	277,578	-
	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-	-	-
	Misc Revenue & Expense	546,879	(156,945)	(28,329)	732,153	-	-	-	-	-	-
	Total Operating Expenses	1,131,176,126	709,439,856	150,202,972	223,085,564	2,470,833	-	14,639,689	19,584,798	11,752,413	-
Operating Revenue for Return		301,002,015	114,513,259	92,234,165	85,296,702	1,085,770	-	868,055	6,666,660	337,405	-
Rate Base											
	Electric Plant in Service	8,433,754,519	3,726,159,697	1,995,748,561	2,476,971,708	32,387,389	-	40,013,011	134,696,106	27,778,047	-
Rate Base	Plant Held for Future Use	-	1,629,231	(203,406)	(1,332,831)	-	-	(47,167)	(45,826)	-	-
	Misc Deferred Debits	67,302,496	57,707,003	3,930,538	640,468	48,763	-	4,113,659	554,375	307,691	-
	Elec Plant Acq Adj	1,749,820	1,749,820	-	-	-	-	-	-	-	-
	Nuclear Fuel	-	-	-	-	-	-	-	-	-	-
	Prepayments	8,805,023	3,720,883	846,972	2,943,471	47,093	-	416,460	534,023	296,121	-
	Fuel Stock	42,986,611	42,986,611	-	-	-	-	-	-	-	-
	Material & Supplies	73,659,471	61,159,021	756,777	11,353,316	-	-	-	390,357	-	-
	Working Capital	8,091,631	(922,939)	1,721,300	5,290,816	76,685	-	639,984	818,003	467,782	-
	Weatherization Loans	(1,363)	-	-	(1,363)	-	-	-	-	-	-
	Miscellaneous Rate Base	-	-	-	-	-	-	-	-	-	-
	Total Electric Plant	8,636,348,208	3,894,189,327	2,002,800,742	2,495,865,585	32,559,929	-	45,135,946	136,947,038	28,849,641	-
Rate Base Deductions											
	Accum Prov For Depr	(3,200,067,136)	(1,498,869,341)	(521,895,028)	(1,143,336,204)	(15,131,118)	-	(2,581,893)	(16,791,374)	(1,462,178)	-
Rate Base Deductions	Accum Prov For Amort	(190,276,927)	(64,300,891)	(18,701,915)	(42,585,267)	(668,497)	-	(26,524,322)	(18,250,338)	(19,245,696)	-
	Accum Def Income Taxes	(591,816,891)	(317,382,398)	(162,120,673)	(101,860,890)	(1,326,533)	-	(1,550,121)	(5,830,655)	(1,745,621)	-
	Unamortized ITC	0	0	0	0	0	-	0	0	0	-
	Customer Adv for Const	(13,802,322)	-	(11,162,027)	(2,497,147)	(32,383)	-	-	(110,766)	-	-
	Customer Service Deposits	-	-	-	-	-	-	-	-	-	-
	Misc. Rate Base Deductions	(445,680,643)	(417,802,670)	(3,564,096)	(16,908,180)	(270,326)	-	(2,382,574)	(3,058,661)	(1,694,135)	-
	Total Rate Base Deductions	(4,441,643,918)	(2,298,355,301)	(717,443,739)	(1,307,187,688)	(17,428,857)	-	(33,038,911)	(44,041,793)	(24,147,630)	-
Total Rate Base		4,194,704,290	1,595,834,026	1,285,357,003	1,188,677,897	15,131,073	-	12,097,035	92,905,245	4,702,011	-
Return on Rate Base		7.176%	7.176%	7.176%	7.176%	7.176%	7.176%	7.176%	7.176%	7.176%	0.000%
Return on Equity		9.265%	9.265%	9.265%	9.265%	9.265%	9.265%	9.265%	9.265%	9.265%	0.000%

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	645,859,269	719,611,917	208,934,852	303,399,015	3,554,826	24,876,786	10,791,648	25,971,018	11,744,653	-
	Less Klamath Surcharge Revenue												
		P	S	-	-	-	-	-	-	-	-	-	-
				645,859,269	719,611,917	208,934,852	303,399,015	3,554,826	24,876,786	10,791,648	25,971,018	11,744,653	-
442	Commercial & Industrial Sales												
			S	658,960,319									
		P	SE	-	-	-	-	-	-	-	-	-	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
				658,960,319	-	-	-	-	-	-	-	-	-
444	Public Street & Highway Lighting												
			S	4,065,127									
			SO	-									
				4,065,127	-	-	-	-	-	-	-	-	-
445	Other Sales to Public Authority												
			S	-									
				-	-	-	-	-	-	-	-	-	-
448	Interdepartmental												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-

Total Sales to Ultimate Customers				**1,308,884,715**	**719,611,917**	**208,934,852**	**303,399,015**	**3,554,826**	**24,876,786**	**10,791,648**	**25,971,018**	**11,744,653**	**-**
447	Sales for Resale-Non NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
447NPC	Sales for Resale-NPC												
		P	SG	73,285,143	73,285,143	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				73,285,143	73,285,143	-	-	-	-	-	-	-	-
	Total Sales for Resale			73,285,143	73,285,143	-	-	-	-	-	-	-	-
449	Provision for Rate Refund												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Sales from Electricity				**1,382,169,858**	**792,897,060**	**208,934,852**	**303,399,015**	**3,554,826**	**24,876,786**	**10,791,648**	**25,971,018**	**11,744,653**	**-**
450	Forfeited Discounts & Interest												
		C_BILLING	S	4,242,722	-	-	-	-	-	4,242,722	-	-	-
		C_BILLING	SO	-	-	-	-	-	-	-	-	-	-
				4,242,722	-	-	-	-	-	4,242,722	-	-	-
451	Misc Electric Revenue												
		CSS_SYS	S	1,062,811	-	-	-	-	-	471,179	247,989	343,642	-
		C_METER	S	25,062	-	-	-	-	-	-	25,062	-	-
		GP	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	9,507	-	-	9,507	-	-	-	-	-	-
				1,097,380	-	-	9,507	-	-	471,179	273,051	343,642	-
453	Water Sales												
		P	SG	15,148	15,148	-	-	-	-	-	-	-	-
				15,148	15,148	-	-	-	-	-	-	-	-
454	Rent of Electric Property												
		D	S	3,723,611	-	-	3,723,611	-	-	-	-	-	-
		T	SG	1,535,450	-	1,535,450	-	-	-	-	-	-	-
		GP	SO	462,646	204,404	109,480	135,878	1,777	-	2,195	7,389	1,524	-
				5,721,707	204,404	1,644,930	3,859,489	1,777	-	2,195	7,389	1,524	-
	Oregon Ancillary Services				24,876,786				(24,876,786)				
456	Other Electric Revenue												
		OTHSGR	S	618,040	109,809	508,219	12	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-	-	-
		OTHSE	SE	4,274,493	-	4,274,493	-	-	-	-	-	-	-
		OTHSO	SO	1,113,616	-	-	1,113,616	-	-	-	-	-	-
		OTHSGR	SG	32,925,178	5,849,908	27,074,642	628	-	-	-	-	-	-
				38,931,326	5,959,717	31,857,355	1,114,255	-	-	-	-	-	-
	Total Other Electric Revenues			**50,008,283**	**31,056,054**	**33,502,285**	**4,983,251**	**1,777**	**(24,876,786)**	**4,716,096**	**280,440**	**345,166**	**-**
Total Electric Operating Revenues				**1,432,178,141**	**823,953,114**	**242,437,137**	**308,382,266**	**3,556,603**	**-**	**15,507,744**	**26,251,458**	**12,089,819**	**-**
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	(44)	(44)	-	-	-	-	-	-	-	-
				(44)	(44)	-	-	-	-	-	-	-	-
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	731,675	-	-	731,675	-	-	-	-	-	-
		T	SG	6,953	-	6,953	-	-	-	-	-	-	-
		T	SG	(35,694)	-	(35,694)	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		PTD	SO	1,617	727	412	478	-	-	-	-	-	-
		P	SG	(157,628)	(157,628)	-	-	-	-	-	-	-	-
				546,923	(156,901)	(28,329)	732,153	-	-	-	-	-	-
Total Miscellaneous Revenues				**546,879**	**(156,945)**	**(28,329)**	**732,153**	**-**	**-**	**-**	**-**	**-**	**-**
Miscellaneous Expenses													
4311	Interest on Customer Deposits												
		C_BILLING	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Miscellaneous Expenses				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Net Misc Revenue and Expense				**546,879**	**(156,945)**	**(28,329)**	**732,153**	**-**	**-**	**-**	**-**	**-**	**-**
500	Operation Supervision & Engineering												
		P	SG	4,058,689	4,058,689	-	-	-	-	-	-	-	-
		P	SG	640,880	640,880	-	-	-	-	-	-	-	-
		P	SG	1,768,725	1,768,725	-	-	-	-	-	-	-	-
				6,468,294	6,468,294	-	-	-	-	-	-	-	-

501	Fuel Related-Non NPC												
		P	S	(5,541)	(5,541)	-	-	-	-	-	-	-	-
		P	SE	13,677,243	13,677,243	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	707,757	707,757	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				14,379,460	14,379,460	-	-	-	-	-	-	-	-
501NPC	Fuel Related-NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	144,408,179	144,408,179	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	11,128,758	11,128,758	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				155,536,937	155,536,937	-	-	-	-	-	-	-	-
	Total Fuel Related			169,916,396	169,916,396	-	-	-	-	-	-	-	-
502	Steam Expenses												
		P	SG	19,389,500	19,389,500	-	-	-	-	-	-	-	-
		P	SG	2,013,621	2,013,621	-	-	-	-	-	-	-	-
		P	SG	672,281	672,281	-	-	-	-	-	-	-	-
				22,075,403	22,075,403	-	-	-	-	-	-	-	-
503	Steam From Other Sources-Non-NPC												
		P	SE	(1,147)	(1,147)	-	-	-	-	-	-	-	-
				(1,147)	(1,147)	-	-	-	-	-	-	-	-
503NPC	Steam From Other Sources-NPC												
		P	SE	1,134,513	1,134,513	-	-	-	-	-	-	-	-
				1,134,513	1,134,513	-	-	-	-	-	-	-	-
505	Electric Expenses												
		P	SG	330,217	330,217	-	-	-	-	-	-	-	-
		P	SG	77,553	77,553	-	-	-	-	-	-	-	-
		P	SG	16,659	16,659	-	-	-	-	-	-	-	-
				424,430	424,430	-	-	-	-	-	-	-	-
506	Misc. Steam Expense												
		P	SG	7,080,758	7,080,758	-	-	-	-	-	-	-	-
		P	SG	(8,636,196)	(8,636,196)	-	-	-	-	-	-	-	-
		P	SG	530,304	530,304	-	-	-	-	-	-	-	-
				(1,025,134)	(1,025,134)	-	-	-	-	-	-	-	-
507	Rents												
		P	SG	134,234	134,234	-	-	-	-	-	-	-	-
		P	SG	5,493	5,493	-	-	-	-	-	-	-	-
				139,727	139,727	-	-	-	-	-	-	-	-
510	Maint Supervision & Engineering												
		P	SG	1,397,814	1,397,814	-	-	-	-	-	-	-	-
		P	SG	707,512	707,512	-	-	-	-	-	-	-	-
		P	SG	(375,703)	(375,703)	-	-	-	-	-	-	-	-
				1,729,623	1,729,623	-	-	-	-	-	-	-	-
511	Maintenance of Structures												
		P	SG	6,006,001	6,006,001	-	-	-	-	-	-	-	-
		P	SG	965,415	965,415	-	-	-	-	-	-	-	-
		P	SG	162,135	162,135	-	-	-	-	-	-	-	-
				7,133,550	7,133,550	-	-	-	-	-	-	-	-
512	Maintenance of Boiler Plant												
		P	SG	23,253,409	23,253,409	-	-	-	-	-	-	-	-
		P	SG	1,597,969	1,597,969	-	-	-	-	-	-	-	-
		P	SG	2,147,461	2,147,461	-	-	-	-	-	-	-	-
				26,998,839	26,998,839	-	-	-	-	-	-	-	-
513	Maintenance of Electric Plant												
		P	SG	9,104,948	9,104,948	-	-	-	-	-	-	-	-
		P	SG	232,059	232,059	-	-	-	-	-	-	-	-
		P	SG	210,781	210,781	-	-	-	-	-	-	-	-
				9,547,788	9,547,788	-	-	-	-	-	-	-	-
514	Maintenance of Misc. Steam Plant												
		P	SG	2,285,065	2,285,065	-	-	-	-	-	-	-	-
		P	SG	412,380	412,380	-	-	-	-	-	-	-	-
		P	SG	70,650	70,650	-	-	-	-	-	-	-	-
				2,768,095	2,768,095	-	-	-	-	-	-	-	-
Total Steam Power Generation				**247,310,378**	**247,310,378**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
517	Operation Super & Engineering												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
518	Nuclear Fuel Expense												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
519	Coolants and Water												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
520	Steam Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
523	Electric Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
524	Misc. Nuclear Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
528	Maintenance Super & Engineering												

		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
529	Maintenance of Structures												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
530	Maintenance of Reactor Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
531	Maintenance of Electric Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
532	Maintenance of Misc Nuclear												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Nuclear Power Generation				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
535	Operation Super & Engineering												
		P	SG	376,025	376,025	-	-	-	-	-	-	-	-
		P	SG	203,718	203,718	-	-	-	-	-	-	-	-
		P	SG	12,970	12,970	-	-	-	-	-	-	-	-
		P	SG	2,079,029	2,079,029	-	-	-	-	-	-	-	-
		P	SG	214,196	214,196	-	-	-	-	-	-	-	-
				2,885,938	2,885,938	-	-	-	-	-	-	-	-
536	Water For Power												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	35	35	-	-	-	-	-	-	-	-
		P	SG	10,213	10,213	-	-	-	-	-	-	-	-
				10,248	10,248	-	-	-	-	-	-	-	-
537	Hydraulic Expenses												
		P	SG	19,543	19,543	-	-	-	-	-	-	-	-
		P	SG	1,059,969	1,059,969	-	-	-	-	-	-	-	-
		P	SG	95,957	95,957	-	-	-	-	-	-	-	-
				1,175,469	1,175,469	-	-	-	-	-	-	-	-
538	Electric Expenses												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
539	Misc. Hydro Expenses												
		P	SG	40,148	40,148	-	-	-	-	-	-	-	-
		P	SG	3,208,588	3,208,588	-	-	-	-	-	-	-	-
		P	SG	1,879,471	1,879,471	-	-	-	-	-	-	-	-
				5,128,207	5,128,207	-	-	-	-	-	-	-	-
540	Rents (Hydro Generation)												
		P	SG	6,900	6,900	-	-	-	-	-	-	-	-
		P	SG	327,982	327,982	-	-	-	-	-	-	-	-
		P	SG	13,985	13,985	-	-	-	-	-	-	-	-
				348,866	348,866	-	-	-	-	-	-	-	-
541	Maint Supervision & Engineering												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	4	4	-	-	-	-	-	-	-	-
		P	SG	122	122	-	-	-	-	-	-	-	-
				126	126	-	-	-	-	-	-	-	-
542	Maintenance of Structures												
		P	SG	1,884	1,884	-	-	-	-	-	-	-	-
		P	SG	126,843	126,843	-	-	-	-	-	-	-	-
		P	SG	6,820	6,820	-	-	-	-	-	-	-	-
				135,547	135,547	-	-	-	-	-	-	-	-
543	Maintenance of Dams & Waterways												
		P	SG	6,660	6,660	-	-	-	-	-	-	-	-
		P	SG	245,042	245,042	-	-	-	-	-	-	-	-
		P	SG	163,924	163,924	-	-	-	-	-	-	-	-
				415,627	415,627	-	-	-	-	-	-	-	-
544	Maintenance of Electric Plant												
		P	SG	4,857	4,857	-	-	-	-	-	-	-	-
		P	SG	442,766	442,766	-	-	-	-	-	-	-	-
		P	SG	76,073	76,073	-	-	-	-	-	-	-	-
				523,696	523,696	-	-	-	-	-	-	-	-
545	Maintenance of Misc. Hydro Plant												
		P	SG	83,778	83,778	-	-	-	-	-	-	-	-
		P	SG	20,064	20,064	-	-	-	-	-	-	-	-
		P	SG	27,697	27,697	-	-	-	-	-	-	-	-
		P	SG	875,842	875,842	-	-	-	-	-	-	-	-
		P	SG	183,826	183,826	-	-	-	-	-	-	-	-
				1,191,206	1,191,206	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation				**11,814,928**	**11,814,928**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
546	Operation Super & Engineering												
		P	SG	72,971	72,971	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	3,069	3,069	-	-	-	-	-	-	-	-
				76,041	76,041	-	-	-	-	-	-	-	-

547	Fuel-Non-NPC												
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
547NPC	Fuel-NPC												
		P	SE	76,737,123	76,737,123	-	-	-	-	-	-	-	-
		P	SE	267,274	267,274	-	-	-	-	-	-	-	-
				77,004,397	77,004,397	-	-	-	-	-	-	-	-
548	Generation Expense												
		P	SG	4,437,793	4,437,793	-	-	-	-	-	-	-	-
		P	SG	186,614	186,614	-	-	-	-	-	-	-	-
		P	SG	373,719	373,719	-	-	-	-	-	-	-	-
				4,998,126	4,998,126	-	-	-	-	-	-	-	-
549	Miscellaneous Other												
		P	S	102,412	102,412	-	-	-	-	-	-	-	-
		P	SG	945,577	945,577	-	-	-	-	-	-	-	-
		P	SG	384,917	384,917	-	-	-	-	-	-	-	-
		P	SG	5,220,407	5,220,407	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				6,653,313	6,653,313	-	-	-	-	-	-	-	-
550	Maint Supervision & Engineering												
		P	S	296,505	296,505	-	-	-	-	-	-	-	-
		P	SG	27,863	27,863	-	-	-	-	-	-	-	-
		P	SG	10,279	10,279	-	-	-	-	-	-	-	-
		P	SG	938,595	938,595	-	-	-	-	-	-	-	-
				1,273,241	1,273,241	-	-	-	-	-	-	-	-
551	Maint Supervision & Engineering												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
552	Maintenance of Structures												
		P	SG	735,642	735,642	-	-	-	-	-	-	-	-
		P	SG	26,837	26,837	-	-	-	-	-	-	-	-
		P	SG	17,725	17,725	-	-	-	-	-	-	-	-
				780,204	780,204	-	-	-	-	-	-	-	-
553	Maint of Generation & Electric Plant												
		P	SG	1,186,688	1,186,688	-	-	-	-	-	-	-	-
		P	SG	2,541,671	2,541,671	-	-	-	-	-	-	-	-
		P	SG	95,996	95,996	-	-	-	-	-	-	-	-
		P	SG	404,803	404,803	-	-	-	-	-	-	-	-
				4,229,157	4,229,157	-	-	-	-	-	-	-	-
554	Maintenance of Misc. Other												
		P	SG	504,075	504,075	-	-	-	-	-	-	-	-
		P	SG	251,975	251,975	-	-	-	-	-	-	-	-
		P	SG	42,434	42,434	-	-	-	-	-	-	-	-
		P	SG	27,837	27,837	-	-	-	-	-	-	-	-
				826,322	826,322	-	-	-	-	-	-	-	-
Total Other Power Generation				**95,840,802**	**95,840,802**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
555	Purchased Power-Non NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
555NPC	Purchased Power-NPC												
		P	S	786,770	786,770	-	-	-	-	-	-	-	-
		P	SG	155,476,734	155,476,734	-	-	-	-	-	-	-	-
		P	SE	3,776,866	3,776,866	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	DGP	-	-	-	-	-	-	-	-	-	-
				160,040,371	160,040,371	-	-	-	-	-	-	-	-
	Total Purchased Power			160,040,371	160,040,371	-	-	-	-	-	-	-	-
556	System Control & Load Dispatch												
		P	SG	239,868	239,868	-	-	-	-	-	-	-	-
				239,868	239,868	-	-	-	-	-	-	-	-
557	Other Expenses												
		P	S	1,731,989	1,731,989	-	-	-	-	-	-	-	-
		P	SG	10,569,175	10,569,175	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		P	SE	2,373	2,373	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
				12,303,537	12,303,537	-	-	-	-	-	-	-	-
2017 Protocol Adjustment													
Baseline ECD		P	S	(11,000,000)	(11,000,000)	-	-	-	-	-	-	-	-
Equalization Adj.		P	S	-	-	-	-	-	-	-	-	-	-
				(11,000,000)	(11,000,000)	-	-	-	-	-	-	-	-
Total Other Power Supply				**161,583,776**	**161,583,776**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL PRODUCTION EXPENSE				**516,549,884**	**516,549,884**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Embedded Cost Differentials												
	Company Owned H	P	DGP	-	-	-	-	-	-	-	-	-	-
	Company Owned H	P	SG	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	MC	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	SG	-	-	-	-	-	-	-	-	-	-
	Existing QF Contra	P	S	-	-	-	-	-	-	-	-	-	-
	Existing QF Contra	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	1,896,906	-	1,896,906	-	-	-	-	-	-	-
		T	SG	555,281	-	555,281	-	-	-	-	-	-	-
				2,452,188	-	2,452,188	-	-	-	-	-	-	-
561	Load Dispatching												
		T	SG	5,203,844	-	5,203,844	-	-	-	-	-	-	-
		T	SG	53,840	-	53,840	-	-	-	-	-	-	-
				5,257,684	-	5,257,684	-	-	-	-	-	-	-
562	Station Expense												
		T	SG	725,707	-	725,707	-	-	-	-	-	-	-
		T	SG	5,678	-	5,678	-	-	-	-	-	-	-
				731,385	-	731,385	-	-	-	-	-	-	-
563	Overhead Line Expense												
		T	SG	270,222	-	270,222	-	-	-	-	-	-	-
		T	SG	2,538	-	2,538	-	-	-	-	-	-	-
				272,759	-	272,759	-	-	-	-	-	-	-
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	35,489,387	-	35,489,387	-	-	-	-	-	-	-
		T	SE	676,299	-	676,299	-	-	-	-	-	-	-
				36,165,687	-	36,165,687	-	-	-	-	-	-	-
	Total Transmission of Electricity by Others			36,165,687	-	36,165,687	-	-	-	-	-	-	-
566	Misc. Transmission Expense												
		T	SG	747,291	-	747,291	-	-	-	-	-	-	-
		T	SG	15,670	-	15,670	-	-	-	-	-	-	-
				762,962	-	762,962	-	-	-	-	-	-	-
567	Rents - Transmission												
		T	SG	552,009	-	552,009	-	-	-	-	-	-	-
		T	SG	11,019	-	11,019	-	-	-	-	-	-	-
				563,028	-	563,028	-	-	-	-	-	-	-
568	Maint Supervision & Engineering												
		T	SG	351,422	-	351,422	-	-	-	-	-	-	-
		T	SG	848	-	848	-	-	-	-	-	-	-
				352,270	-	352,270	-	-	-	-	-	-	-
569	Maintenance of Structures												
		T	SG	1,511,020	-	1,511,020	-	-	-	-	-	-	-
		T	SG	20,413	-	20,413	-	-	-	-	-	-	-
				1,531,433	-	1,531,433	-	-	-	-	-	-	-
570	Maintenance of Station Equipment												
		STEP_UP	SG	3,085,319	227,074	2,858,246	-	-	-	-	-	-	-
		STEP_UP	SG	37,092	2,730	34,362	-	-	-	-	-	-	-
				3,122,411	229,803	2,892,607	-	-	-	-	-	-	-
571	Maintenance of Overhead Lines												
		T	SG	4,204,195	-	4,204,195	-	-	-	-	-	-	-
		T	SG	549,923	-	549,923	-	-	-	-	-	-	-
				4,754,118	-	4,754,118	-	-	-	-	-	-	-
572	Maintenance of Underground Lines												
		T	SG	9,822	-	9,822	-	-	-	-	-	-	-
		T	SG	75	-	75	-	-	-	-	-	-	-
				9,898	-	9,898	-	-	-	-	-	-	-
573	Maint of Misc. Transmission Plant												
		T	SG	39,242	-	39,242	-	-	-	-	-	-	-
		T	SG	1,198	-	1,198	-	-	-	-	-	-	-
				40,440	-	40,440	-	-	-	-	-	-	-
TOTAL TRANSMISSION EXPENSE				**56,016,262**	**229,803**	**55,786,458**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
580	Operation Supervision & Engineering												
		D_SPLIT	S	1,052,279	-	-	995,228	12,906	-	-	44,145	-	-
		D_SPLIT	SNPD	2,800,509	-	-	2,648,674	34,348	-	-	117,487	-	-
				3,852,787	-	-	3,643,902	47,254	-	-	161,632	-	-
581	Load Dispatching												
		D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	3,255,597	-	-	3,255,597	-	-	-	-	-	-
				3,255,597	-	-	3,255,597	-	-	-	-	-	-
582	Station Expense												
		D	S	1,075,700	-	-	1,075,700	-	-	-	-	-	-
		D	SNPD	985	-	-	985	-	-	-	-	-	-
				1,076,685	-	-	1,076,685	-	-	-	-	-	-
583	Overhead Line Expenses												
		D	S	1,661,832	-	-	1,661,832	-	-	-	-	-	-
		D	SNPD	44	-	-	44	-	-	-	-	-	-
				1,661,875	-	-	1,661,875	-	-	-	-	-	-
584	Underground Line Expense												
		D	S	545	-	-	545	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				545	-	-	545	-	-	-	-	-	-
585	Street Lighting & Signal Systems												
		DL	S	-	-	-	-	-	-	-	-	-	-
		DL	SNPD	56,953	-	-	-	56,953	-	-	-	-	-

				56,953	-	-	-	56,953	-	-	-	-	-
586	Meter Expenses												
		C_Meter	S	747,014	-	-	-	-	-	-	747,014	-	-
		C_Meter	SNPD	-	-	-	-	-	-	-	-	-	-
				747,014	-	-	-	-	-	-	747,014	-	-
587	Customer Installation Expenses												
		D	S	5,540,670	-	-	5,540,670	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				5,540,670	-	-	5,540,670	-	-	-	-	-	-
588	Misc. Distribution Expenses												
		D	S	80,257	-	-	80,257	-	-	-	-	-	-
		D	SNPD	213,427	-	-	213,427	-	-	-	-	-	-
				293,685	-	-	293,685	-	-	-	-	-	-
589	Rents												
		D	S	1,644,054	-	-	1,644,054	-	-	-	-	-	-
		D	SNPD	3,595	-	-	3,595	-	-	-	-	-	-
				1,647,649	-	-	1,647,649	-	-	-	-	-	-
590	Maint Supervision & Engineering												
		D_SPLIT	S	951,464	-	-	899,878	11,670	-	-	39,916	-	-
		D_SPLIT	SNPD	666,300	-	-	630,176	8,172	-	-	27,953	-	-
				1,617,764	-	-	1,530,054	19,842	-	-	67,868	-	-
591	Maintenance of Structures												
		D	S	450,973	-	-	450,973	-	-	-	-	-	-
		D	SNPD	49,762	-	-	49,762	-	-	-	-	-	-
				500,735	-	-	500,735	-	-	-	-	-	-
592	Maintenance of Station Equipment												
		D	S	2,666,737	-	-	2,666,737	-	-	-	-	-	-
		D	SNPD	496,844	-	-	496,844	-	-	-	-	-	-
				3,163,581	-	-	3,163,581	-	-	-	-	-	-
593	Maintenance of Overhead Lines												
		D	S	35,707,602	-	-	35,707,602	-	-	-	-	-	-
		D	SNPD	806,874	-	-	806,874	-	-	-	-	-	-
				36,514,476	-	-	36,514,476	-	-	-	-	-	-
594	Maintenance of Underground Lines												
		D	S	6,307,761	-	-	6,307,761	-	-	-	-	-	-
		D	SNPD	6,627	-	-	6,627	-	-	-	-	-	-
				6,314,388	-	-	6,314,388	-	-	-	-	-	-
595	Maintenance of Line Transformers												
		D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	257,587	-	-	257,587	-	-	-	-	-	-
				257,587	-	-	257,587	-	-	-	-	-	-
596	Maint of Street Lighting & Signal Sys.												
		DL	S	856,129	-	-	-	856,129	-	-	-	-	-
		DL	SNPD	-	-	-	-	-	-	-	-	-	-
				856,129	-	-	-	856,129	-	-	-	-	-
597	Maintenance of Meters												
		C_Meter	S	260,199	-	-	-	-	-	-	260,199	-	-
		C_Meter	SNPD	(71,260)	-	-	-	-	-	-	(71,260)	-	-
				188,939	-	-	-	-	-	-	188,939	-	-
598	Maint of Misc. Distribution Plant												
		D	S	635,939	-	-	635,939	-	-	-	-	-	-
		D	SNPD	1,543,150	-	-	1,543,150	-	-	-	-	-	-
				2,179,089	-	-	2,179,089	-	-	-	-	-	-
TOTAL DISTRIBUTION EXPENSE				**69,726,150**	**-**	**-**	**67,580,518**	**980,178**	**-**	**-**	**1,165,454**	**-**	**-**
901	Supervision												
		CUST901	S	-	-	-	-	-	-	-	-	-	-
		CUST901	CN	849,460	-	-	-	-	-	253,678	457,024	138,758	-
				849,460	-	-	-	-	-	253,678	457,024	138,758	-
902	Meter Reading Expense												
		C_Meter	S	7,318,815	-	-	-	-	-	-	7,318,815	-	-
		C_Meter	CN	236,158	-	-	-	-	-	-	236,158	-	-
				7,554,973	-	-	-	-	-	-	7,554,973	-	-
903	Customer Receipts & Collections												
		CUST903	S	2,449,632	-	-	-	-	-	1,445,658	235,448	768,525	-
		CUST903	CN	14,278,353	-	-	-	-	-	8,426,415	1,372,376	4,479,561	-
				16,727,984	-	-	-	-	-	9,872,073	1,607,824	5,248,087	-
904	Uncollectible Accounts												
		REVREQ	S	5,041,346	2,900,360	853,392	1,085,522	12,519	-	54,588	92,407	42,557	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		REVREQ	CN	21,113	12,147	3,574	4,546	52	-	229	387	178	-
				5,062,459	2,912,507	856,966	1,090,069	12,572	-	54,817	92,794	42,735	-
905	Misc. Customer Accounts Expense												
		CUST905	S	-	-	-	-	-	-	-	-	-	-
		CUST905	CN	7,227	-	-	-	-	-	-	-	7,227	-
				7,227	-	-	-	-	-	-	-	7,227	-
TOTAL CUSTOMER ACCOUNTS EXPENSE				**30,202,104**	**2,912,507**	**856,966**	**1,090,069**	**12,572**	**-**	**10,180,568**	**9,712,615**	**5,436,807**	**-**
907	Supervision												
		C_Service	S	-	-	-	-	-	-	-	-	-	-
		C_Service	CN	163	-	-	-	-	-	-	-	163	-
				163	-	-	-	-	-	-	-	163	-
908	Customer Assistance												
		DSM	S	2,317,803	-	-	2,317,803	-	-	-	-	-	-
		C_Service	CN	965,585	-	-	-	-	-	-	-	965,585	-
				3,283,388	-	-	2,317,803	-	-	-	-	965,585	-
909	Informational & Instructional Adv												
		C_Service	S	2,007,072	-	-	-	-	-	-	-	2,007,072	-
		C_Service	CN	845,391	-	-	-	-	-	-	-	845,391	-
				2,852,463	-	-	-	-	-	-	-	2,852,463	-

910	Misc. Customer Service												
		C_Service	S	-	-	-	-	-	-	-	-	-	-
		C_Service	CN	5,317	-	-	-	-	-	-	-	5,317	-
				5,317	-	-	-	-	-	-	-	5,317	-
TOTAL CUSTOMER SERVICE EXPENSE				**6,141,331**	**-**	**-**	**2,317,803**	**-**	**-**	**-**	**-**	**3,823,527**	**-**
911	Supervision												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
912	Demonstration & Selling Expense												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
913	Advertising Expense												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
916	Misc. Sales Expense												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL SALES EXPENSE				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total Customer Service Exp Including Sales				**6,141,331**	**-**	**-**	**2,317,803**	**-**	**-**	**-**	**-**	**3,823,527**	**-**
920	Administrative & General Salaries												
		LABOR	S	9,198	3,742	701	3,299	53	-	469	601	333	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	21,444,692	8,725,647	1,634,886	7,690,825	123,157	-	1,092,911	1,400,150	777,117	-
				21,453,889	8,729,389	1,635,587	7,694,124	123,210	-	1,093,379	1,400,750	777,450	-
921	Office Supplies & expenses												
		LABOR	S	59,030	24,019	4,500	21,170	339	-	3,008	3,854	2,139	-
		LABOR	CN	28,980	11,792	2,209	10,393	166	-	1,477	1,892	1,050	-
		LABOR	SO	2,983,671	1,214,028	227,467	1,070,050	17,135	-	152,060	194,807	108,123	-
				3,071,681	1,249,839	234,177	1,101,614	17,641	-	156,546	200,554	111,312	-
922	Office Supplies & expenses												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(9,077,067)	(3,693,375)	(692,011)	(3,255,357)	(52,130)	-	(462,605)	(592,653)	(328,936)	-
				(9,077,067)	(3,693,375)	(692,011)	(3,255,357)	(52,130)	-	(462,605)	(592,653)	(328,936)	-
923	Outside Services												
		LABOR	S	129,678	52,765	9,886	46,507	745	-	6,609	8,467	4,699	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	5,974,184	2,430,840	455,456	2,142,554	34,310	-	304,469	390,062	216,494	-
				6,103,862	2,483,605	465,342	2,189,061	35,054	-	311,078	398,529	221,193	-
924	Property Insurance												
		DPW	S	7,829,803	-	-	7,569,542	-	-	-	260,261	-	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
		GP	SO	778,810	344,090	184,296	228,734	2,991	-	3,695	12,438	2,565	-
				8,608,613	344,090	184,296	7,798,276	2,991	-	3,695	272,700	2,565	-
925	Injuries & Damages												
		DPW	S	1,096,772	-	-	1,060,316	-	-	-	36,456	-	-
		LABOR	SO	1,915,476	779,390	146,031	686,958	11,001	-	97,621	125,064	69,413	-
				3,012,248	779,390	146,031	1,747,273	11,001	-	97,621	161,520	69,413	-
926	Employee Pensions & Benefits												
		LABOR	S	(4,122,384)	(1,677,360)	(314,280)	(1,478,433)	(23,675)	-	(210,094)	(269,155)	(149,388)	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	35,513,770	14,450,224	2,707,475	12,736,494	203,955	-	1,809,929	2,318,737	1,286,954	-
				31,391,385	12,772,864	2,393,196	11,258,061	180,281	-	1,599,835	2,049,581	1,137,567	-
927	Franchise Requirements												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
928	Regulatory Commission Expense												
		D	S	4,437,868	-	-	4,437,868	-	-	-	-	-	-
		P	SE	2,029	2,029	-	-	-	-	-	-	-	-
		D	SO	901,342	-	-	901,342	-	-	-	-	-	-
		FERC	SG	1,426,505	718,910	707,595	-	-	-	-	-	-	-
				6,767,743	720,939	707,595	5,339,209	-	-	-	-	-	-
929	Duplicate Charges												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(37,896,478)	(15,419,727)	(2,889,127)	(13,591,018)	(217,639)	-	(1,931,362)	(2,474,307)	(1,373,299)	-
				(37,896,478)	(15,419,727)	(2,889,127)	(13,591,018)	(217,639)	-	(1,931,362)	(2,474,307)	(1,373,299)	-
930	Misc General Expenses												
		LABOR	S	(665)	(271)	(51)	(239)	(4)	-	(34)	(43)	(24)	-
		C_SERVICE	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	452,783	184,233	34,519	162,384	2,600	-	23,076	29,563	16,408	-
				452,118	183,963	34,468	162,146	2,597	-	23,042	29,519	16,384	-
931	Rents												
		LABOR	S	273,657	111,348	20,863	98,143	1,572	-	13,947	17,867	9,917	-
		LABOR	SO	614,180	249,904	46,823	220,267	3,527	-	31,301	40,101	22,257	-
				887,837	361,253	67,686	318,410	5,099	-	45,248	57,968	32,174	-
935	Maintenance of General Plant												
		G	S	172,151	36,432	60,744	70,085	-	-	2,480	2,410	-	-
		B_Center	CN	18,865	-	-	-	-	-	13,747	-	5,118	-
		G	SO	6,506,002	1,376,864	2,295,662	2,648,675	-	-	93,733	91,069	-	-
				6,697,019	1,413,296	2,356,407	2,718,760	-	-	109,960	93,478	5,118	-
TOTAL ADMINISTRATIVE & GEN EXPENSE				**41,472,852**	**9,925,526**	**4,643,647**	**23,480,558**	**108,103**	**-**	**1,046,437**	**1,597,640**	**670,940**	**-**
TOTAL O&M EXPENSE				**720,108,582**	**529,617,720**	**61,287,072**	**94,468,948**	**1,100,853**	**-**	**11,227,005**	**12,475,709**	**9,931,275**	**-**
403SP	Steam Depreciation												
		P	SG	7,850,960	7,850,960	-	-	-	-	-	-	-	-
		P	SG	7,840,853	7,840,853	-	-	-	-	-	-	-	-

			P	SG	118,077,160	118,077,160	-	-	-	-	-	-	-	-
			P	SG	3,941,176	3,941,176	-	-	-	-	-	-	-	-
					137,710,149	137,710,149	-	-	-	-	-	-	-	-
403NP		Nuclear Depreciation												
			P	SG	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
403HP		Hydro Depreciation												
			P	SG	(19,402)	(19,402)	-	-	-	-	-	-	-	-
			P	SG	360,756	360,756	-	-	-	-	-	-	-	-
			P	SG	4,747,761	4,747,761	-	-	-	-	-	-	-	-
			P	SG	1,973,121	1,973,121	-	-	-	-	-	-	-	-
			P	SG	1,055,803	1,055,803	-	-	-	-	-	-	-	-
					8,118,040	8,118,040	-	-	-	-	-	-	-	-
403OP		Other Production Depreciation												
			P	S	5,998	5,998	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-	-	-
			P	SG	47,051,228	47,051,228	-	-	-	-	-	-	-	-
			P	SG	848,083	848,083	-	-	-	-	-	-	-	-
			P	SG	13,024,223	13,024,223	-	-	-	-	-	-	-	-
					60,929,531	60,929,531	-	-	-	-	-	-	-	-
403TP		Transmission Depreciation												
			T_Split	S	-	-	-	-	-	-	-	-	-	-
			T_Split	SG	2,255,104	48,140	2,206,964	-	-	-	-	-	-	-
			T_Split	SG	2,816,579	60,126	2,756,452	-	-	-	-	-	-	-
			T_Split	SG	31,848,156	679,870	31,168,286	-	-	-	-	-	-	-
					36,919,839	788,137	36,131,702	-	-	-	-	-	-	-
403		Distribution Depreciation												
	360	Land & Land Rights	D	S	112,505	-	-	112,505	-	-	-	-	-	-
	361	Structures	D	S	668,970	-	-	668,970	-	-	-	-	-	-
	362	Station Equipment	D	S	6,229,726	-	-	6,229,726	-	-	-	-	-	-
	363	Storage Battery Equipr	D	S	-	-	-	-	-	-	-	-	-	-
	364	Poles & Towers	D	S	13,814,159	-	-	13,814,159	-	-	-	-	-	-
	365	OH Conductors	D	S	7,694,002	-	-	7,694,002	-	-	-	-	-	-
	366	UG Conduit	D	S	2,214,891	-	-	2,214,891	-	-	-	-	-	-
	367	UG Conductor	D	S	4,688,543	-	-	4,688,543	-	-	-	-	-	-
	368	Line Trans	D	S	12,236,082	-	-	12,236,082	-	-	-	-	-	-
	369	Services	D	S	7,440,425	-	-	7,440,425	-	-	-	-	-	-
	370	Meters	C_Meter	S	3,234,886	-	-	-	-	-	-	3,234,886	-	-
	371	Inst Cust Prem	DL	S	133,307	-	-	-	133,307	-	-	-	-	-
	372	Leased Property	D	S	-	-	-	-	-	-	-	-	-	-
	373	Street Lighting	DL	S	748,191	-	-	-	748,191	-	-	-	-	-
					59,215,689	-	-	55,099,305	881,498	-	-	3,234,886	-	-
403GP		General Depreciation												
			TD	S	5,794,774	-	2,681,362	3,113,412	-	-	-	-	-	-
			G-DGP	SG	6,183	4,072	2,112	-	-	-	-	-	-	-
			G-DGU	SG	19,008	12,517	6,491	-	-	-	-	-	-	-
			P	SE	29,470	29,470	-	-	-	-	-	-	-	-
			B_Center	CN	264,100	-	-	-	-	-	192,451	-	71,649	-
			G-SG	SG	2,652,735	1,101,435	1,551,300	-	-	-	-	-	-	-
			LABOR	SO	4,860,977	1,977,886	370,588	1,743,318	27,917	-	247,736	317,379	176,153	-
			P	SG	2,130	2,130	-	-	-	-	-	-	-	-
			P	SG	37,560	37,560	-	-	-	-	-	-	-	-
					13,666,937	3,165,070	4,611,853	4,856,730	27,917	-	440,186	317,379	247,802	-
403GV0		General Vehicles												
			G-SG	SG	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
403MP		Mining Depreciation												
			P	SE	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
403EP		Experimental Plant Depreciation												
			P	SG	-	-	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
4031		ARO Depreciation												
			P	S	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
TOTAL DEPRECIATION EXPENSE					**316,560,184**	**210,710,926**	**40,743,555**	**59,956,035**	**909,414**	**-**	**440,186**	**3,552,265**	**247,802**	**-**
404GP		Amort of LT Plant - Capital Lease Gen												
			TD	S	249,902	-	115,635	134,267	-	-	-	-	-	-
			I-SG	SG	-	-	-	-	-	-	-	-	-	-
			LABOR	SO	77,388	31,488	5,900	27,754	444	-	3,944	5,053	2,804	-
			I-DGU	SG	-	-	-	-	-	-	-	-	-	-
			B_Center	CN	-	-	-	-	-	-	-	-	-	-
			I-DGP	SG	-	-	-	-	-	-	-	-	-	-
					327,289	31,488	121,534	162,021	444	-	3,944	5,053	2,804	-
404SP		Amort of LT Plant - Cap Lease Steam												
			P	SG	-	-	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
404IP		Amort of LT Plant - Intangible Plant												
			TD	S	13,738	-	6,357	7,381	-	-	-	-	-	-
			P	SE	-	-	-	-	-	-	-	-	-	-
			I-SG	SG	1,988,315	1,310,900	677,415	-	-	-	-	-	-	-
			LABOR	SO	4,474,792	1,820,752	341,146	1,604,819	25,699	-	228,054	292,165	162,158	-
			CSS_SYS	CN	3,324,664	-	-	-	-	-	1,473,934	775,755	1,074,975	-
			I-SG	SG	680,958	448,957	232,001	-	-	-	-	-	-	-
			I-SG	SG	81,920	54,010	27,910	-	-	-	-	-	-	-
			I-DGP	SG	20,466	20,466	-	-	-	-	-	-	-	-
			I-SG	SG	-	-	-	-	-	-	-	-	-	-
			I-SG	SG	5,634	3,714	1,919	-	-	-	-	-	-	-
			I-DGU	SG	4,290	4,290	-	-	-	-	-	-	-	-
					10,594,776	3,663,089	1,286,748	1,612,200	25,699	-	1,701,988	1,067,919	1,237,133	-
404MP		Amort of LT Plant - Mining Plant												
			P	SE	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-

404OP	Amort of LT Plant - Other Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
404HP	Amortization of Other Electric Plant												
		P	SG	81,111	81,111	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				81,111	81,111	-	-	-	-	-	-	-	-
Total Amortization of Limited Term Plant				**11,003,177**	**3,775,689**	**1,408,283**	**1,774,221**	**26,143**	**-**	**1,705,932**	**1,072,972**	**1,239,937**	**-**
405	Amortization of Other Electric Plant												
		GP	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
406	Amortization of Plant Acquisition Adj												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	1,244,288	1,244,288	-	-	-	-	-	-	-	-
		P	SO	-	-	-	-	-	-	-	-	-	-
				1,244,288	1,244,288	-	-	-	-	-	-	-	-
407	Amort of Prop Losses, Unrec Plant, etc												
		D_SPLIT	S	(1,796,203)	-	-	(1,698,819)	(22,030)	-	-	(75,354)	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
		P	SG	10,640,558	10,640,558	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
				8,844,354	10,640,558	-	(1,698,819)	(22,030)	-	-	(75,354)	-	-
TOTAL AMORTIZATION EXPENSE				**21,091,819**	**15,660,534**	**1,408,283**	**75,402**	**4,113**	**-**	**1,705,932**	**997,618**	**1,239,937**	**-**
408	Taxes Other Than Income												
		D	S	32,909,920	-	-	32,909,920	-	-	-	-	-	-
		GP	GPS	49,349,831	21,803,498	11,678,056	14,493,917	189,514	-	234,135	788,170	162,542	-
		REVREQ	SO	3,364,059	1,935,392	569,463	724,362	8,354	-	36,426	61,662	28,398	-
		P	SE	211,668	211,668	-	-	-	-	-	-	-	-
		P	SG	517,635	517,635	-	-	-	-	-	-	-	-
		DSM	OPRV-ID	-	-	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-	-	-
		GP	SG	-	-	-	-	-	-	-	-	-	-
				86,353,112	24,468,193	12,247,519	48,128,199	197,868	-	270,561	849,832	190,940	-
41140	Deferred Investment Tax Credit - Fed												
		PTD	DGU	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
41141	Deferred Investment Tax Credit - Idaho												
		PTD	DGU	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL DEFERRED ITC				-	-	-	-	-	-	-	-	-	-
427	Interest on Long-Term Debt												
		NP	S	92,980,612	39,877,001	26,827,261	23,801,878	305,813	-	201,078	1,837,234	130,346	-
		NP	SNP	-	-	-	-	-	-	-	-	-	-
				92,980,612	39,877,001	26,827,261	23,801,878	305,813	-	201,078	1,837,234	130,346	-
428	Amortization of Debt Disc & Exp												
		NP	SNP	1,172,671	502,928	338,345	300,189	3,857	-	2,536	23,171	1,644	-
				1,172,671	502,928	338,345	300,189	3,857	-	2,536	23,171	1,644	-
429	Amortization of Premium on Debt												
		NP	SNP	(2,899)	(1,243)	(836)	(742)	(10)	-	(6)	(57)	(4)	-
				(2,899)	(1,243)	(836)	(742)	(10)	-	(6)	(57)	(4)	-
431	Other Interest Expense												
		NUTIL	OTH	-	-	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
		NP	SNP	5,781,217	2,479,416	1,668,028	1,479,920	19,014	-	12,502	114,233	8,104	-
				5,781,217	2,479,416	1,668,028	1,479,920	19,014	-	12,502	114,233	8,104	-
432	AFUDC - Borrowed												
		NP	SNP	(6,695,742)	(2,871,632)	(1,931,891)	(1,714,027)	(22,022)	-	(14,480)	(132,303)	(9,387)	-
				(6,695,742)	(2,871,632)	(1,931,891)	(1,714,027)	(22,022)	-	(14,480)	(132,303)	(9,387)	-
	Total Electric Interest Deductions for Tax			93,235,859	39,986,470	26,900,906	23,867,218	306,653	-	201,630	1,842,278	130,704	-
	Non-Utility Portion of Interest												
	427	NUTIL	NUTIL	-	-	-	-	-	-	-	-	-	-
	428	NUTIL	NUTIL	-	-	-	-	-	-	-	-	-	-
	429	NUTIL	NUTIL	-	-	-	-	-	-	-	-	-	-
	431	NUTIL	NUTIL	-	-	-	-	-	-	-	-	-	-
	Total Non-utility Interest			-	-	-	-	-	-	-	-	-	-
	Total Interest Deductions for Tax			93,235,859	39,986,470	26,900,906	23,867,218	306,653	-	201,630	1,842,278	130,704	-
419	Interest & Dividends												
		GP	S	-	-	-	-	-	-	-	-	-	-
		GP	SNP	(18,867,154)	(8,335,792)	(4,464,689)	(5,541,234)	(72,454)	-	(89,513)	(301,329)	(62,142)	-
	Total Operating Deductions for Tax			(18,867,154)	(8,335,792)	(4,464,689)	(5,541,234)	(72,454)	-	(89,513)	(301,329)	(62,142)	-
41010	Deferred Income Tax - Federal-DR												
		GP	S	2,485,004	1,097,912	588,047	729,839	9,543	-	11,790	39,688	8,185	-
		P	SCHMDEXP	-	-	-	-	-	-	-	-	-	-
		PT	SG	21,732	13,869	7,863	-	-	-	-	-	-	-
		LABOR	SO	1,602,163	651,905	122,145	574,592	9,201	-	81,653	104,607	58,059	-
		NP	SNP	6,545,496	2,807,196	1,888,541	1,675,565	21,528	-	14,155	129,335	9,176	-

		P	SE	(1,242,969)	(1,242,969)	-	-	-	-	-	-	-	-
		PT	SG	29,314,634	18,707,953	10,606,681	-	-	-	-	-	-	-
		GP	GPS	3,016,955	1,332,936	713,927	886,072	11,586	-	14,314	48,184	9,937	-
		TAXDEPR	TAXDEPR	60,786,561	34,027,388	11,079,715	14,664,967	14,324	-	388,934	342,898	268,336	-
		C_BILLING	BADDEBT	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		D	SNPD	0	-	-	0	-	-	-	-	-	-
				102,529,576	57,396,190	25,006,919	18,531,036	66,182	-	510,846	664,712	353,693	-
41110	Deferred Income Tax - Federal-CR												
		GP	S	(14,328,322)	(6,330,468)	(3,390,628)	(4,208,191)	(55,024)	-	(67,979)	(228,839)	(47,193)	-
		P	SE	(2,061,309)	(2,061,309)	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	(0)	-	-	-	-	-	(0)	-	-	-
		NP	SNP	(3,857,636)	(1,654,441)	(1,113,026)	(987,507)	(12,688)	-	(8,342)	(76,224)	(5,408)	-
		PT	SG	(89,649)	(57,212)	(32,437)	-	-	-	-	-	-	-
		D_SPLIT	CIAC	(4,865,809)	-	-	(4,602,001)	(59,678)	-	-	(204,131)	-	-
		LABOR	SO	(643,707)	(261,918)	(49,074)	(230,856)	(3,697)	-	(32,806)	(42,028)	(23,327)	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	(579)	-	-	-	-	-	(257)	(135)	(187)	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	(60,151,601)	(35,016,102)	(10,293,772)	(14,045,614)	(226,818)	-	(86,369)	(482,926)	-	-
		P	TROJD	(0)	(0)	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		P	SG	(28,068,497)	(28,068,497)	-	-	-	-	-	-	-	-
		GP	GPS	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(114,067,109)	(73,449,948)	(14,878,938)	(24,074,168)	(357,904)	-	(195,754)	(1,034,283)	(76,115)	-
TOTAL DEFERRED INCOME TAXES				(11,537,533)	(16,053,758)	10,127,981	(5,543,132)	(291,722)	-	315,092	(369,571)	277,578	-
SCHMAF	Additions - Flow Through												
		SCHMAF	S	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SNP	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SO	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SE	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SCHMAP	Additions - Permanent												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	4,518	4,518	-	-	-	-	-	-	-	-
		PTD	SNP	-	-	-	-	-	-	-	-	-	-
		SCHMAP-SO	SO	1,011,865	795,318	27,835	130,939	2,097	-	18,607	23,838	13,231	-
		SCHMAP	SG	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	38,238	22,259	6,544	8,929	144	-	55	307	-	-
				1,054,621	822,096	34,378	139,868	2,241	-	18,662	24,145	13,231	-
SCHMAT	Additions - Temporary												
		SCHMAT-SITUS	S	(11,279,520)	(21,628,114)	3,541,129	6,519,414	2,330	-	20,681	250,334	14,705	-
		SCHMAT-SG	GPS	0	0	-	-	-	-	-	-	-	-
		D_SPLIT	CIAC	19,790,493	-	-	18,717,516	242,726	-	-	830,251	-	-
		SCHMAT-SNP	SNP	15,689,995	7,494,118	3,888,544	4,162,989	-	-	578	143,397	370	-
		P	TROJD	0	0	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	(0)	-	-	-	-	-	(0)	-	-	-
		SCHMAT-SE	SE	8,383,879	8,383,772	14	65	1	-	9	12	7	-
		SCHMAT-SG	GPS	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	2,355	-	-	-	-	-	1,044	550	761	-
		SCHMAT-SO	SO	2,618,124	1,066,736	203,097	937,048	14,919	-	132,391	169,795	94,137	-
		SCHMAT-SNP	SNPD	-	-	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	244,651,971	142,419,458	41,867,409	57,127,109	922,525	-	351,287	1,964,183	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	116,914,740	116,914,740	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				396,772,036	254,650,710	49,500,192	87,464,141	1,182,502	-	505,990	3,358,521	109,980	-
TOTAL SCHEDULE - M ADDITIONS				397,826,658	255,472,806	49,534,571	87,604,009	1,184,743	-	524,652	3,382,667	123,211	-
SCHMDF	Deductions - Flow Through												
		SCHMDF	S	-	-	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SCHMDP	Deductions - Permanent												
		SCHMDP	S	-	-	-	-	-	-	-	-	-	-
		P	SE	889,862	889,862	-	-	-	-	-	-	-	-
		SCHMDP	SNP	0	0	0	0	(0)	-	(0)	(0)	(0)	-
		BOOKDEPR	SCHMDEXP	140,360	81,708	24,020	32,775	529	-	202	1,127	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDP-SO	SO	-	-	-	-	-	-	-	-	-	-
				1,030,222	971,570	24,020	32,775	529	-	202	1,127	(0)	-
SCHMDT	Deductions - Temporary												
		SCHMDT-SITUS	S	10,107,177	13,368,871	351,024	(801,762)	(28,092)	-	(2,309,782)	(299,105)	(173,977)	-
		SCHMDT	BADDEBT	-	-	-	-	-	-	-	-	-	-
		SCHMDT-SNP	SNP	26,622,210	12,720,110	6,596,864	7,062,412	-	-	-	242,825	-	-
		SCHMDT	CN	-	-	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	88,389	89,313	(924)	-	-	-	-	-	-	-
		SCHMDT-SG	SG	121,850,780	123,124,561	(1,273,781)	-	-	-	-	-	-	-
		P	SE	(5,055,474)	(5,055,474)	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDT-GPS	GPS	12,270,731	5,862,963	3,040,632	3,255,213	-	-	-	111,923	-	-
		SCHMDT-SO	SO	6,516,407	2,678,971	765,770	2,333,481	25,961	-	234,835	310,727	166,662	-
		TAXDEPR	TAXDEPR	247,234,512	138,398,103	45,064,037	59,646,176	58,259	-	1,581,894	1,394,653	1,091,390	-
		SCHMDT-SNP	SNPD	(0)	(0)	(0)	(0)	-	-	-	(0)	-	-
				419,634,732	291,187,419	54,543,621	71,495,520	56,128	-	(493,053)	1,761,022	1,084,075	-
TOTAL SCHEDULE - M DEDUCTIONS				420,664,954	292,158,989	54,567,641	71,528,294	56,657	-	(492,851)	1,762,149	1,084,075	-
TOTAL SCHEDULE - M ADJUSTMENTS				(22,838,296)	(36,686,183)	(5,033,070)	16,075,715	1,128,085	-	1,017,504	1,620,517	(960,864)	-
40911	State Income Taxes												
		IBT		8,640,100	(1,120,662)	4,508,663	4,665,815	101,616	-	125,733	383,884	(24,950)	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-

	PTC	P	SG	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
TOTAL STATE TAXES				8,640,100	(1,120,662)	4,508,663	4,665,815	101,616	-	125,733	383,884	(24,950)	-
Calculation of Taxable Income:													
	Operating Revenues			1,432,178,141	823,953,114	242,437,137	308,382,266	3,556,603	-	15,507,744	26,251,458	12,089,819	-
	Operating Deductions:												
	O & M Expenses			720,108,582	529,617,720	61,287,072	94,468,948	1,100,853	-	11,227,005	12,475,709	9,931,275	-
	Depreciation Expense			316,560,184	210,710,926	40,743,555	59,956,035	909,414	-	440,186	3,552,265	247,802	-
	Amortization Expense			21,091,819	15,660,534	1,408,283	75,402	4,113	-	1,705,932	997,618	1,239,937	-
	Taxes Other Than Income			86,353,112	24,468,193	12,247,519	48,128,199	197,868	-	270,561	849,832	190,940	-
	Interest & Dividends (AFUDC-Equity)			(18,867,154)	(8,335,792)	(4,464,689)	(5,541,234)	(72,454)	-	(89,513)	(301,329)	(62,142)	-
	Misc Revenue & Expense			546,879	(156,945)	(28,329)	732,153	-	-	-	-	-	-
	Total Operating Deductions			1,125,793,424	771,964,636	111,193,410	197,819,504	2,139,794	-	13,554,172	17,574,096	11,547,812	-
	Other Deductions:												
	Interest Deductions			93,235,859	39,986,470	26,900,906	23,867,218	306,653	-	201,630	1,842,278	130,704	-
	Interest on PCRBS			-	-	-	-	1	-	-	-	-	-
	Schedule M Adjustments			(22,838,296)	(36,686,183)	(5,033,070)	16,075,715	1,128,085	-	1,017,504	1,620,517	(960,864)	-
	Income Before State Taxes			190,310,563	(24,684,175)	99,309,750	102,771,259	2,238,240	-	2,769,445	8,455,602	(549,561)	-
	State Income Taxes			8,640,100	(1,120,662)	4,508,663	4,665,815	101,616	-	125,733	383,884	(24,950)	-
Total Taxable Income				181,670,463	(23,563,513)	94,801,088	98,105,444	2,136,624	-	2,643,712	8,071,717	(524,611)	-
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				38,150,797.24	(4,948,338)	19,908,228	20,602,143	448,691	-	555,180	1,695,061	(110,168)	-
Adjustments to Calculated Tax:													
40910	PMI	P	SE	(4,518)	(4,518)	-	-	-	-	-	-	-	-
40910	Renewable Energy Cre	P	SG	(48,733,297)	(48,733,297)	-	-	-	-	-	-	-	-
40910		P	SO	-	-	-	-	-	-	-	-	-	-
40910		P	S	-	-	-	-	-	-	-	-	-	-
Federal Income Tax				(10,587,018)	(53,686,153)	19,908,228	20,602,143	448,691	-	555,180	1,695,061	(110,168)	-
TOTAL OPERATING EXPENSES				**1,131,176,126**	**709,439,856**	**150,202,972**	**223,085,564**	**2,470,833**	**-**	**14,639,689**	**19,584,798**	**11,752,413**	**-**
310	Land and Land Rights												
		P	SG	605,853	605,853	-	-	-	-	-	-	-	-
		P	SG	8,805,400	8,805,400	-	-	-	-	-	-	-	-
		P	SG	14,101,375	14,101,375	-	-	-	-	-	-	-	-
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	685,779	685,779	-	-	-	-	-	-	-	-
				24,198,407	24,198,407	-	-	-	-	-	-	-	-
311	Structures and Improvements												
		P	SG	59,107,295	59,107,295	-	-	-	-	-	-	-	-
		P	SG	81,719,497	81,719,497	-	-	-	-	-	-	-	-
		P	SG	111,859,540	111,859,540	-	-	-	-	-	-	-	-
		P	SG	17,045,133	17,045,133	-	-	-	-	-	-	-	-
				269,731,465	269,731,465	-	-	-	-	-	-	-	-
312	Boiler Plant Equipment												
		P	SG	153,818,280	153,818,280	-	-	-	-	-	-	-	-
		P	SG	121,849,985	121,849,985	-	-	-	-	-	-	-	-
		P	SG	717,478,735	717,478,735	-	-	-	-	-	-	-	-
		P	SG	88,968,495	88,968,495	-	-	-	-	-	-	-	-
				1,082,115,495	1,082,115,495	-	-	-	-	-	-	-	-
314	Turbogenerator Units												
		P	SG	28,512,914	28,512,914	-	-	-	-	-	-	-	-
		P	SG	28,554,947	28,554,947	-	-	-	-	-	-	-	-
		P	SG	185,547,712	185,547,712	-	-	-	-	-	-	-	-
		P	SG	17,980,632	17,980,632	-	-	-	-	-	-	-	-
				260,596,206	260,596,206	-	-	-	-	-	-	-	-
315	Accessory Electric Equipment												
		P	SG	22,403,357	22,403,357	-	-	-	-	-	-	-	-
		P	SG	34,727,839	34,727,839	-	-	-	-	-	-	-	-
		P	SG	52,037,017	52,037,017	-	-	-	-	-	-	-	-
		P	SG	17,872,772	17,872,772	-	-	-	-	-	-	-	-
				127,040,984	127,040,984	-	-	-	-	-	-	-	-
316	Misc Power Plant Equipment												
		P	SG	674,802	674,802	-	-	-	-	-	-	-	-
		P	SG	1,295,165	1,295,165	-	-	-	-	-	-	-	-
		P	SG	5,544,256	5,544,256	-	-	-	-	-	-	-	-
		P	SG	1,082,369	1,082,369	-	-	-	-	-	-	-	-
				8,596,592	8,596,592	-	-	-	-	-	-	-	-
317	Steam Plant ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SP	Unclassified Steam Plant - Account 300												
		P	SG	14,627,372	14,627,372	-	-	-	-	-	-	-	-
				14,627,372	14,627,372	-	-	-	-	-	-	-	-
Total Steam Production Plant				**1,786,906,522**	**1,786,906,522**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
320	Land and Land Rights												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
321	Structures and Improvements												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
322	Reactor Plant Equipment												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
323	Turbogenerator Units												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-

324	Land and Land Rights												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
325	Misc. Power Plant Equipment												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
NP	Unclassified Nuclear Plant - Acct 300												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Nuclear Production Plant				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
330	Land and Land Rights												
		P	SG	2,688,755	2,688,755	-	-	-	-	-	-	-	-
		P	SG	1,370,956	1,370,956	-	-	-	-	-	-	-	-
		P	SG	5,058,943	5,058,943	-	-	-	-	-	-	-	-
		P	SG	332,793	332,793	-	-	-	-	-	-	-	-
				9,451,447	9,451,447	-	-	-	-	-	-	-	-
331	Structures and Improvements												
		P	SG	5,130,406	5,130,406	-	-	-	-	-	-	-	-
		P	SG	1,274,078	1,274,078	-	-	-	-	-	-	-	-
		P	SG	62,851,157	62,851,157	-	-	-	-	-	-	-	-
		P	SG	3,137,413	3,137,413	-	-	-	-	-	-	-	-
				72,393,055	72,393,055	-	-	-	-	-	-	-	-
332	Reservoirs, Dams & Waterways												
		P	SG	37,875,711	37,875,711	-	-	-	-	-	-	-	-
		P	SG	4,899,297	4,899,297	-	-	-	-	-	-	-	-
		P	SG	87,897,989	87,897,989	-	-	-	-	-	-	-	-
		P	SG	23,859,526	23,859,526	-	-	-	-	-	-	-	-
		P	SG	(7,878,054)	(7,878,054)	-	-	-	-	-	-	-	-
				146,654,469	146,654,469	-	-	-	-	-	-	-	-
333	Water Wheel, Turbines, & Generators												
		P	SG	7,519,675	7,519,675	-	-	-	-	-	-	-	-
		P	SG	1,954,068	1,954,068	-	-	-	-	-	-	-	-
		P	SG	16,692,961	16,692,961	-	-	-	-	-	-	-	-
		P	SG	10,034,263	10,034,263	-	-	-	-	-	-	-	-
				36,200,968	36,200,968	-	-	-	-	-	-	-	-
334	Accessory Electric Equipment												
		P	SG	960,772	960,772	-	-	-	-	-	-	-	-
		P	SG	878,240	878,240	-	-	-	-	-	-	-	-
		P	SG	17,440,399	17,440,399	-	-	-	-	-	-	-	-
		P	SG	2,819,749	2,819,749	-	-	-	-	-	-	-	-
				22,099,159	22,099,159	-	-	-	-	-	-	-	-
335	Misc. Power Plant Equipment												
		P	SG	293,977	293,977	-	-	-	-	-	-	-	-
		P	SG	40,211	40,211	-	-	-	-	-	-	-	-
		P	SG	303,393	303,393	-	-	-	-	-	-	-	-
		P	SG	4,757	4,757	-	-	-	-	-	-	-	-
				642,337	642,337	-	-	-	-	-	-	-	-
336	Roads, Railroads & Bridges												
		P	SG	1,137,259	1,137,259	-	-	-	-	-	-	-	-
		P	SG	199,097	199,097	-	-	-	-	-	-	-	-
		P	SG	4,781,871	4,781,871	-	-	-	-	-	-	-	-
		P	SG	377,451	377,451	-	-	-	-	-	-	-	-
				6,495,678	6,495,678	-	-	-	-	-	-	-	-
337	Hydro Plant ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
HP	Unclassified Hydro Plant - Acct 300												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Hydraulic Plant				**293,937,113**	**293,937,113**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
340	Land and Land Rights												
		P	S	74,986	74,986	-	-	-	-	-	-	-	-
		P	SG	10,154,683	10,154,683	-	-	-	-	-	-	-	-
		P	SG	1,587,451	1,587,451	-	-	-	-	-	-	-	-
		P	SG	61,187	61,187	-	-	-	-	-	-	-	-
				11,878,306	11,878,306	-	-	-	-	-	-	-	-
341	Structures and Improvements												
		P	SG	43,397,696	43,397,696	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	14,006,274	14,006,274	-	-	-	-	-	-	-	-
		P	SG	1,111,947	1,111,947	-	-	-	-	-	-	-	-
				58,515,918	58,515,918	-	-	-	-	-	-	-	-
342	Fuel Holders, Producers & Accessories												
		P	SG	3,494,550	3,494,550	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	718,051	718,051	-	-	-	-	-	-	-	-
				4,212,602	4,212,602	-	-	-	-	-	-	-	-
343	Prime Movers												
		P	S	129,823	129,823	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	261,042,504	261,042,504	-	-	-	-	-	-	-	-
		P	SG	840,119,605	840,119,605	-	-	-	-	-	-	-	-
		P	SG	15,073,254	15,073,254	-	-	-	-	-	-	-	-
				1,116,365,187	1,116,365,187	-	-	-	-	-	-	-	-
344	Generators												

		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	14,797,865	14,797,865	-	-	-	-	-	-	-	-
		P	SG	102,766,352	102,766,352	-	-	-	-	-	-	-	-
		P	SG	4,627,543	4,627,543	-	-	-	-	-	-	-	-
				122,191,760	122,191,760	-	-	-	-	-	-	-	-
345	Accessory Electric Plant												
		P	SG	51,768,643	51,768,643	-	-	-	-	-	-	-	-
		P	SG	29,502,942	29,502,942	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	755,045	755,045	-	-	-	-	-	-	-	-
				82,026,629	82,026,629	-	-	-	-	-	-	-	-
346	Misc. Power Plant Equipment												
		P	SG	3,103,765	3,103,765	-	-	-	-	-	-	-	-
		P	SG	868,544	868,544	-	-	-	-	-	-	-	-
				3,972,309	3,972,309	-	-	-	-	-	-	-	-
347	Other Production ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
OP	Unclassified Other Prod Plant-Acct 300												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(143,950)	(143,950)	-	-	-	-	-	-	-	-
				(143,950)	(143,950)	-	-	-	-	-	-	-	-
Total Other Production Plant				**1,399,018,761**	**1,399,018,761**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Experimental Plant													
103	Experimental Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
Total Experimental Plant				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL PRODUCTION PLANT				**3,479,862,396**	**3,479,862,396**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
350	Land and Land Rights												
		T	SG	5,480,759	-	5,480,759	-	-	-	-	-	-	-
		T	SG	12,543,903	-	12,543,903	-	-	-	-	-	-	-
		T	SG	52,610,876	-	52,610,876	-	-	-	-	-	-	-
				70,635,538	-	70,635,538	-	-	-	-	-	-	-
352	Structures and Improvements												
		T	S	-	-	-	-	-	-	-	-	-	-
		T	SG	1,828,385	-	1,828,385	-	-	-	-	-	-	-
		T	SG	4,601,404	-	4,601,404	-	-	-	-	-	-	-
		T	SG	65,899,954	-	65,899,954	-	-	-	-	-	-	-
				72,329,743	-	72,329,743	-	-	-	-	-	-	-
353	Station Equipment												
		STEP_UP	SG	27,666,499	2,036,201	25,630,298	-	-	-	-	-	-	-
		STEP_UP	SG	40,079,588	2,949,781	37,129,807	-	-	-	-	-	-	-
		STEP_UP	SG	504,510,131	37,130,977	467,379,155	-	-	-	-	-	-	-
				572,256,218	42,116,959	530,139,259	-	-	-	-	-	-	-
354	Towers and Fixtures												
		T	SG	33,337,301	-	33,337,301	-	-	-	-	-	-	-
		T	SG	34,165,595	-	34,165,595	-	-	-	-	-	-	-
		T	SG	271,715,073	-	271,715,073	-	-	-	-	-	-	-
				339,217,969	-	339,217,969	-	-	-	-	-	-	-
355	Poles and Fixtures												
		T	S	-	-	-	-	-	-	-	-	-	-
		T	SG	15,932,852	-	15,932,852	-	-	-	-	-	-	-
		T	SG	29,924,135	-	29,924,135	-	-	-	-	-	-	-
		T	SG	507,633,613	-	507,633,613	-	-	-	-	-	-	-
				553,490,600	-	553,490,600	-	-	-	-	-	-	-
356	Clearing and Grading												
		T	SG	41,233,041	-	41,233,041	-	-	-	-	-	-	-
		T	SG	41,052,840	-	41,052,840	-	-	-	-	-	-	-
		T	SG	248,329,735	-	248,329,735	-	-	-	-	-	-	-
				330,615,616	-	330,615,616	-	-	-	-	-	-	-
357	Underground Conduit												
		T	SG	1,658	-	1,658	-	-	-	-	-	-	-
		T	SG	23,850	-	23,850	-	-	-	-	-	-	-
		T	SG	960,053	-	960,053	-	-	-	-	-	-	-
				985,561	-	985,561	-	-	-	-	-	-	-
358	Underground Conductors												
		T	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	283,010	-	283,010	-	-	-	-	-	-	-
		T	SG	1,808,001	-	1,808,001	-	-	-	-	-	-	-
				2,091,011	-	2,091,011	-	-	-	-	-	-	-
359	Roads and Trails												
		T	SG	484,810	-	484,810	-	-	-	-	-	-	-
		T	SG	114,633	-	114,633	-	-	-	-	-	-	-
		T	SG	2,506,931	-	2,506,931	-	-	-	-	-	-	-
				3,106,374	-	3,106,374	-	-	-	-	-	-	-
TP	Unclassified Trans Plant - Acct 300												
		T	SG	28,217,936	-	28,217,936	-	-	-	-	-	-	-
				28,217,936	-	28,217,936	-	-	-	-	-	-	-
TS0	Unclassified Trans Sub Plant - Acct 300												
		T	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL TRANSMISSION PLANT				**1,972,946,565**	**42,116,959**	**1,930,829,606**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
360	Land and Land Rights												
		D	S	15,425,674	-	-	15,425,674	-	-	-	-	-	-
				15,425,674	-	-	15,425,674	-	-	-	-	-	-
361	Structures and Improvements												
		D	S	34,943,680	-	-	34,943,680	-	-	-	-	-	-
				34,943,680	-	-	34,943,680	-	-	-	-	-	-
362	Station Equipment												
		D	S	278,179,324	-	-	278,179,324	-	-	-	-	-	-
				278,179,324	-	-	278,179,324	-	-	-	-	-	-

363	Storage Battery Equipment												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
364	Poles, Towers & Fixtures												
		D	S	419,657,606	-	-	419,657,606	-	-	-	-	-	-
				419,657,606	-	-	419,657,606	-	-	-	-	-	-
365	Overhead Conductors												
		D	S	287,716,469	-	-	287,716,469	-	-	-	-	-	-
				287,716,469	-	-	287,716,469	-	-	-	-	-	-
366	Underground Conduit												
		D	S	105,322,979	-	-	105,322,979	-	-	-	-	-	-
				105,322,979	-	-	105,322,979	-	-	-	-	-	-
367	Underground Conductors												
		D	S	207,955,594	-	-	207,955,594	-	-	-	-	-	-
				207,955,594	-	-	207,955,594	-	-	-	-	-	-
368	Line Transformers												
		D	S	487,686,594	-	-	487,686,594	-	-	-	-	-	-
				487,686,594	-	-	487,686,594	-	-	-	-	-	-
369	Services												
		D	S	314,454,032	-	-	314,454,032	-	-	-	-	-	-
				314,454,032	-	-	314,454,032	-	-	-	-	-	-
370	Meters												
		C_Meter	S	96,105,719	-	-	-	-	-	-	96,105,719	-	-
				96,105,719	-	-	-	-	-	-	96,105,719	-	-
371	Installations on Customers' Premises												
		DL	S	2,809,929	-	-	-	2,809,929	-	-	-	-	-
				2,809,929	-	-	-	2,809,929	-	-	-	-	-
372	Leased Property												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
373	Street Lights												
		DL	S	25,286,848	-	-	-	25,286,848	-	-	-	-	-
				25,286,848	-	-	-	25,286,848	-	-	-	-	-
DP	Unclassified Dist Plant - Acct 300												
		D	S	15,304,313	-	-	15,304,313	-	-	-	-	-	-
				15,304,313	-	-	15,304,313	-	-	-	-	-	-
DS0	Unclassified Dist Sub Plant - Acct 300												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL DISTRIBUTION PLANT				**2,290,848,762**	**-**	**-**	**2,166,646,266**	**28,096,777**	**-**	**-**	**96,105,719**	**-**	**-**
389	Land and Land Rights												
		D_SPLIT	S	6,114,113	-	-	5,782,625	74,988	-	-	256,499	-	-
		B_Center	CN	352,286	-	-	-	-	-	256,713	-	95,573	-
		G-DGU	SG	86	57	30	-	-	-	-	-	-	-
		G-SG	SG	319	133	187	-	-	-	-	-	-	-
		LABOR	SO	2,045,585	832,330	155,950	733,619	11,748	-	104,252	133,559	74,128	-
				8,512,391	832,519	156,166	6,516,245	86,736	-	360,964	390,058	169,702	-
390	Structures and Improvements												
		D_SPLIT	S	39,510,644	-	-	37,368,503	484,590	-	-	1,657,551	-	-
		P	SE	310,151	310,151	-	-	-	-	-	-	-	-
		G-DGP	SG	87,238	57,446	29,792	-	-	-	-	-	-	-
		G-DGU	SG	387,050	254,870	132,180	-	-	-	-	-	-	-
		B_Center	CN	2,562,207	-	-	-	-	-	1,867,094	-	695,113	-
		G-SG	SG	1,505,877	625,251	880,626	-	-	-	-	-	-	-
		LABOR	SO	26,275,962	10,691,446	2,003,209	9,423,490	150,903	-	1,339,132	1,715,589	952,193	-
				70,639,129	11,939,164	3,045,808	46,791,993	635,492	-	3,206,226	3,373,140	1,647,307	-
391	Office Furniture & Equipment												
		D_SPLIT	S	2,191,143	-	-	2,072,346	26,874	-	-	91,923	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	1,261,380	-	-	-	-	-	919,174	-	342,206	-
		G-SG	SG	828,377	343,948	484,429	-	-	-	-	-	-	-
		P	SE	2,519	2,519	-	-	-	-	-	-	-	-
		LABOR	SO	14,003,915	5,698,064	1,067,621	5,022,299	80,424	-	713,698	914,332	507,476	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	1,051	1,051	-	-	-	-	-	-	-	-
				18,288,385	6,045,581	1,552,050	7,094,645	107,298	-	1,632,872	1,006,255	849,682	-
392	Transportation Equipment												
		D_SPLIT	S	24,809,266	-	-	23,464,187	304,280	-	-	1,040,799	-	-
		LABOR	SO	1,876,176	763,399	143,035	672,863	10,775	-	95,618	122,498	67,989	-
		G-SG	SG	5,472,510	2,272,226	3,200,285	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	118,427	77,984	40,444	-	-	-	-	-	-	-
		P	SE	122,518	122,518	-	-	-	-	-	-	-	-
		G-DGP	SG	18,376	12,101	6,276	-	-	-	-	-	-	-
		P	SG	77,943	77,943	-	-	-	-	-	-	-	-
		P	SG	11,620	11,620	-	-	-	-	-	-	-	-
				32,506,837	3,337,790	3,390,039	24,137,050	315,055	-	95,618	1,163,296	67,989	-
393	Stores Equipment												
		D_SPLIT	S	2,635,106	-	-	2,492,239	32,319	-	-	110,548	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	69,422	28,247	5,293	24,897	399	-	3,538	4,533	2,516	-
		G-SG	SG	1,524,977	633,181	891,796	-	-	-	-	-	-	-
		P	SG	14,045	14,045	-	-	-	-	-	-	-	-
				4,243,550	675,473	897,088	2,517,136	32,718	-	3,538	115,081	2,516	-
394	Tools, Shop & Garage Equipment												
		D_SPLIT	S	10,475,442	-	-	9,907,497	128,479	-	-	439,466	-	-
		G-DGP	SG	24,301	16,002	8,299	-	-	-	-	-	-	-

		G-SG	SG	5,813,914	2,413,979	3,399,935	-	-	-	-	-	-	-
		LABOR	SO	578,920	235,557	44,135	207,621	3,325	-	29,504	37,798	20,979	-
		P	SE	27,372	27,372	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	446,768	446,768	-	-	-	-	-	-	-	-
		P	SG	23,398	23,398	-	-	-	-	-	-	-	-
				17,390,114	3,163,075	3,452,369	10,115,118	131,804	-	29,504	477,264	20,979	-
395	Laboratory Equipment												
		D_SPLIT	S	7,887,804	-	-	7,460,152	96,742	-	-	330,909	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	1,353,563	550,752	103,192	485,436	7,774	-	68,983	88,376	49,051	-
		P	SE	315,773	315,773	-	-	-	-	-	-	-	-
		G-SG	SG	1,659,653	689,100	970,553	-	-	-	-	-	-	-
		P	SG	58,183	58,183	-	-	-	-	-	-	-	-
		P	SG	3,649	3,649	-	-	-	-	-	-	-	-
				11,278,624	1,617,457	1,073,745	7,945,588	104,516	-	68,983	419,285	49,051	-
396	Power Operated Equipment												
		D_SPLIT	S	40,611,944	-	-	38,410,094	498,097	-	-	1,703,753	-	-
		G-DGP	SG	68,179	44,896	23,284	-	-	-	-	-	-	-
		G-SG	SG	11,448,423	4,753,467	6,694,955	-	-	-	-	-	-	-
		LABOR	SO	1,658,281	674,739	126,423	594,718	9,524	-	84,513	108,271	60,093	-
		G-DGU	SG	275,190	181,211	93,979	-	-	-	-	-	-	-
		P	SE	59,412	59,412	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	358,679	358,679	-	-	-	-	-	-	-	-
				54,480,108	6,072,404	6,938,641	39,004,812	507,620	-	84,513	1,812,024	60,093	-
397	Communication Equipment												
		D_SPLIT	S	94,814,269	-	-	89,673,742	1,162,877	-	-	3,977,650	-	-
		G-DGP	SG	107,355	70,692	36,662	-	-	-	-	-	-	-
		G-DGU	SG	295,812	194,791	101,022	-	-	-	-	-	-	-
		LABOR	SO	30,277,021	12,319,440	2,308,239	10,858,411	173,881	-	1,543,043	1,976,823	1,097,184	-
		B_Center	CN	323,567	-	-	-	-	-	235,785	-	87,782	-
		G-SG	SG	48,474,021	20,126,761	28,347,260	-	-	-	-	-	-	-
		P	SE	72,721	72,721	-	-	-	-	-	-	-	-
		G-SG	SG	334,603	138,930	195,673	-	-	-	-	-	-	-
		G-SG	SG	4,328	1,797	2,531	-	-	-	-	-	-	-
				174,703,697	32,925,132	30,991,388	100,532,153	1,336,758	-	1,778,828	5,954,473	1,184,966	-
398	Misc. Equipment												
		D_SPLIT	S	1,107,524	-	-	1,047,478	13,584	-	-	46,463	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	25,753	-	-	-	-	-	18,766	-	6,987	-
		LABOR	SO	600,137	244,190	45,753	215,230	3,447	-	30,585	39,184	21,748	-
		P	SE	995	995	-	-	-	-	-	-	-	-
		G-SG	SG	706,236	293,234	413,002	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				2,440,646	538,420	458,755	1,262,708	17,030	-	49,352	85,647	28,735	-
399	Coal Mine												
		P	SE	21,270,957	21,270,957	-	-	-	-	-	-	-	-
MP	Unckassified Mine Plant	P	SE	-	-	-	-	-	-	-	-	-	-
				21,270,957	21,270,957	-	-	-	-	-	-	-	-
399L	WIDCO Capital Lease												
		P	SE	-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
1011390	General Capital Leases												
		D_SPLIT	S	2,257,880	-	-	2,135,465	27,692	-	-	94,723	-	-
		P	SG	3,045,577	3,045,577	-	-	-	-	-	-	-	-
		LABOR	SO	513,669	209,007	39,161	184,220	2,950	-	26,179	33,538	18,614	-
				5,817,126	3,254,584	39,161	2,319,684	30,642	-	26,179	128,261	18,614	-
	Remove Capital Leases			(5,817,126)	(3,254,584)	(39,161)	(2,319,684)	(30,642)	-	(26,179)	(128,261)	(18,614)	-
				-	-	-	-	-	-	-	-	-	-
1011346	General Gas Line Capital Leases												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
GP	Unclassified Gen Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	10,732,817	4,367,084	818,241	3,849,168	61,639	-	546,989	700,759	388,938	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
				10,732,817	4,367,084	818,241	3,849,168	61,639	-	546,989	700,759	388,938	-
399G	Unclassified Gen Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL GENERAL PLANT				**426,487,256**	**92,785,057**	**52,774,291**	**249,766,617**	**3,336,666**	**-**	**7,857,387**	**15,497,282**	**4,469,957**	**-**
301	Organization												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
302	Franchise & Consent												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	1,100,347	725,461	374,886	-	-	-	-	-	-	-
		I-DGP	SG	45,540,725	45,540,725	-	-	-	-	-	-	-	-
		I-DGU	SG	2,433,220	2,433,220	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	156,394	156,394	-	-	-	-	-	-	-	-
				49,230,686	48,855,800	374,886	-	-	-	-	-	-	-

303	Miscellaneous Intangible Plant												
		D_SPLIT	S	5,489,081	-	-	5,191,481	67,322	-	-	230,278	-	-
		LABOR	SG	44,652,823	18,168,821	3,404,212	16,014,082	256,441	-	2,275,693	2,915,436	1,618,137	-
		LABOR	SO	109,730,568	44,648,354	8,365,566	39,353,264	630,182	-	5,592,325	7,164,441	3,976,436	-
		P	SE	(277,690)	(277,690)	-	-	-	-	-	-	-	-
		CSS_SYS	CN	54,784,072	-	-	-	-	-	24,287,605	12,782,950	17,713,517	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
				214,378,854	62,539,485	11,769,779	60,558,826	953,946	-	32,155,624	23,093,105	23,308,090	-
303	Less Non-Utility Plant												
		I-SITUS	S	-	-	-	-	-	-	-	-	-	-
				214,378,854	62,539,485	11,769,779	60,558,826	953,946	-	32,155,624	23,093,105	23,308,090	-
IP	Unclassified Intangible Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL INTANGIBLE PLANT				**263,609,540**	**111,395,285**	**12,144,665**	**60,558,826**	**953,946**	**-**	**32,155,624**	**23,093,105**	**23,308,090**	**-**
TOTAL ELECTRIC PLANT IN SERVICE				**8,433,754,519**	**3,726,159,697**	**1,995,748,561**	**2,476,971,708**	**32,387,389**	**-**	**40,013,011**	**134,696,106**	**27,778,047**	**-**
105	Plant Held For Future Use												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	951,787	-	951,787	-	-	-	-	-	-	-
		P	SG	2,322,078	2,322,078	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		G	SG	(3,273,865)	(692,847)	(1,155,193)	(1,332,831)	-	-	(47,167)	(45,826)	-	-
				-	1,629,231	(203,406)	(1,332,831)	-	-	(47,167)	(45,826)	-	-
114	Electric Plant Acquisition Adjustments												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	37,655,972	37,655,972	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				37,655,972	37,655,972	-	-	-	-	-	-	-	-
115	Accum Provision for Asset Acquisition Adjustments												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(35,906,153)	(35,906,153)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(35,906,153)	(35,906,153)	-	-	-	-	-	-	-	-
128	Pensions												
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
124	Weatherization												
		DSM	S	0	-	-	0	-	-	-	-	-	-
		DSM	SO	(1,363)	-	-	(1,363)	-	-	-	-	-	-
				(1,363)	-	-	(1,363)	-	-	-	-	-	-
182W	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
186W	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	CN	-	-	-	-	-	-	-	-	-	-
		DSM	CNP	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Total Weatherization			(1,363)	-	-	(1,363)	-	-	-	-	-	-
151	Fuel Stock												
		P	DEU	-	-	-	-	-	-	-	-	-	-
		P	SE	40,432,763	40,432,763	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	3,751,520	3,751,520	-	-	-	-	-	-	-	-
				44,184,283	44,184,283	-	-	-	-	-	-	-	-
152	Fuel Stock - Undistributed												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25316	DG&T Working Capital Deposit												
		P	SE	(517,960)	(517,960)	-	-	-	-	-	-	-	-
				(517,960)	(517,960)	-	-	-	-	-	-	-	-
25317	DG&T Working Capital Deposit												
		P	SE	(679,712)	(679,712)	-	-	-	-	-	-	-	-
				(679,712)	(679,712)	-	-	-	-	-	-	-	-
25319	Provo Working Capital Deposit												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Total Fuel Stock			42,986,611	42,986,611	-	-	-	-	-	-	-	-
154	Materials and Supplies												
		MSS	S	41,769,971	34,681,358	429,145	6,438,108	-	-	-	221,359	-	-
		MSS	SG	(416,755)	(346,029)	(4,282)	(64,235)	-	-	-	(2,209)	-	-
		MSS	SE	-	-	-	-	-	-	-	-	-	-
		MSS	SO	91,495	75,967	940	14,102	-	-	-	485	-	-
		MSS	SG	30,279,678	25,141,037	311,093	4,667,081	-	-	-	160,467	-	-
		MSS	SG	2,070	1,719	21	319	-	-	-	11	-	-
		MSS	SNPD	(466,126)	(387,022)	(4,789)	(71,845)	-	-	-	(2,470)	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	2,470,181	2,050,976	25,379	380,735	-	-	-	13,091	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
				73,730,513	61,218,006	757,507	11,364,265	-	-	-	390,734	-	-
163	Stores Expense Undistributed												

		MSS	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25318	Provo Working Capital Deposit												
		MSS	SG	(71,042)	(58,986)	(730)	(10,950)	-	-	-	(376)	-	-
				(71,042)	(58,986)	(730)	(10,950)	-	-	-	(376)	-	-
	Total Materials & Supplies			73,659,471	61,159,021	756,777	11,353,316	-	-	-	390,357	-	-
165	Prepayments												
		LABOR	S	3,030,864	1,233,231	231,065	1,086,975	17,406	-	154,465	197,889	109,833	-
		GP	GPS	49,317	21,789	11,670	14,484	189	-	234	788	162	-
		PT	SG	587,773	375,104	212,669	-	-	-	-	-	-	-
		P	SE	901	901	-	-	-	-	-	-	-	-
		LABOR	SO	5,136,167	2,089,859	391,568	1,842,011	29,497	-	261,760	335,347	186,125	-
				8,805,023	3,720,883	846,972	2,943,471	47,093	-	416,460	534,023	296,121	-
182M	Misc Regulatory Assets												
		DDS2	S	(9,204,116)	(9,198,816)	(532,480)	(2,924,415)	(8,323)	-	3,607,068	(94,628)	(52,521)	-
		DEFSG	SG	897,435	750,615	146,819	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		DEFSG	SG	-	-	-	-	-	-	-	-	-	-
		P	SE	43,547,079	43,547,079	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	9,895,254	4,026,287	754,388	3,548,788	56,828	-	504,303	646,073	358,586	-
				45,135,652	39,125,166	368,727	624,373	48,505	-	4,111,372	551,445	306,065	-
186M	Misc Deferred Debits												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		DEFSG	SG	21,750,684	18,192,295	3,558,390	-	-	-	-	-	-	-
		LABOR	SO	44,878	18,260	3,421	16,095	258	-	2,287	2,930	1,626	-
		P	SE	371,282	371,282	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-	-	-
				22,166,844	18,581,837	3,561,811	16,095	258	-	2,287	2,930	1,626	-
Working Capital													
CWC	Cash Working Capital												
		CWC	S	7,708,249	4,783,713	938,497	1,608,356	17,716	-	116,685	147,594	95,689	-
		CWC	SO	-	-	-	-	-	-	-	-	-	-
		CWC	SE	-	-	-	-	-	-	-	-	-	-
				7,708,249	4,783,713	938,497	1,608,356	17,716	-	116,685	147,594	95,689	-
OWC	Other Work. Cap.												
131	Cash	GP	SNP	-	-	-	-	-	-	-	-	-	-
135	Working Funds	GP	SG	-	-	-	-	-	-	-	-	-	-
141	Notes Receivable	GP	SO	-	-	-	-	-	-	-	-	-	-
143	Other A/R	LABOR	SO	12,207,884	4,967,275	930,697	4,378,179	70,110	-	622,164	797,067	442,392	-
232	A/P	LABOR	S	-	-	-	-	-	-	-	-	-	-
232	A/P	LABOR	SO	(1,939,905)	(789,329)	(147,893)	(695,719)	(11,141)	-	(98,866)	(126,659)	(70,299)	-
232	A/P	P	SE	(455,292)	(455,292)	-	-	-	-	-	-	-	-
232	A/P	P	SG	(534,288)	(534,288)	-	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	S	-	-	-	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	SE	(1,755,018)	(1,755,018)	-	-	-	-	-	-	-	-
230	Asset Retir. Oblig.	P	SE	-	-	-	-	-	-	-	-	-	-
230	Asset Retir. Oblig.	P	S	-	-	-	-	-	-	-	-	-	-
254	Decom. Reg Liability	P	SG	(5,320,279)	(5,320,279)	-	-	-	-	-	-	-	-
254	Reclam. Reg Liability	P	SE	(1,819,719)	(1,819,719)	-	-	-	-	-	-	-	-
2533	Cholla Reclamation	P	SE	-	-	-	-	-	-	-	-	-	-
				383,382	(5,706,651)	782,803	3,682,461	58,969	-	523,299	670,409	372,093	-
Total Working Capital				8,091,631	(922,939)	1,721,300	5,290,816	76,685	-	639,984	818,003	467,782	-
Miscellaneous Rate Base													
18221	Unrec Plant & Reg Study Costs												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
18222	Nuclear Plant - Trojan												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
		P	TROJD	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
1869	Misc Deferred Debits-Trojan												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL MISCELLANEOUS RATE BASE				-	-	-	-	-	-	-	-	-	-
TOTAL RATE BASE ADDITIONS				**202,593,689**	**168,029,630**	**7,052,181**	**18,893,877**	**172,540**	**-**	**5,122,935**	**2,250,932**	**1,071,594**	**-**
235	Customer Service Deposits												
		C_BILLING	S	-	-	-	-	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
2281	Prov for Property Insuranc	LABOR	S	11,606,109	4,722,418	884,819	4,162,361	66,654	-	591,496	757,777	420,584	-
2282	Prov for Injuries & Damag	LABOR	SO	(4,431,019)	(1,802,940)	(337,809)	(1,589,120)	(25,447)	-	(225,823)	(289,307)	(160,572)	-
2282	Prov for Injuries & Damag	LABOR	S	(8,767,623)	(3,567,465)	(668,420)	(3,144,380)	(50,352)	-	(446,834)	(572,449)	(317,723)	-
2283	Prov for Pensions and Ben	LABOR	SO	(449,265)	(182,802)	(34,251)	(161,122)	(2,580)	-	(22,896)	(29,333)	(16,281)	-
2283	Prov for Pensions and Ben	LABOR	S	-	-	-	-	-	-	-	-	-	-
25335	Pens Oblig	LABOR	SE	(28,896,607)	(11,757,762)	(2,203,000)	(10,363,345)	(165,953)	-	(1,472,691)	(1,886,694)	(1,047,160)	-
254	Reg Liabilities - Insurance	LABOR	SO	-	-	-	-	-	-	-	-	-	-
				(30,938,405)	(12,588,551)	(2,358,662)	(11,095,606)	(177,679)	-	(1,576,750)	(2,020,006)	(1,121,152)	-
22841	Accum Misc Oper Provisions - Other												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(133,339)	(133,339)	-	-	-	-	-	-	-	-
				(133,339)	(133,339)	-	-	-	-	-	-	-	-
254105	ARO	P	S	-	-	-	-	-	-	-	-	-	-
230	ARO	P	TROJD	(709,453)	(709,453)	-	-	-	-	-	-	-	-
254105	ARO	P	TROJD	(682,403)	(682,403)	-	-	-	-	-	-	-	-
254		P	S	(388,516,991)	(388,516,991)	-	-	-	-	-	-	-	-
				(389,908,847)	(389,908,847)	-	-	-	-	-	-	-	-

252	Customer Advances for Construction												
		D_SPLIT	S	(2,640,295)	-	-	(2,497,147)	(32,383)	-	-	(110,766)	-	-
		T	SE	-	-	-	-	-	-	-	-	-	-
		T	SG	(11,162,027)	-	(11,162,027)	-	-	-	-	-	-	-
		D_SPLIT	SO	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
				(13,802,322)	-	(11,162,027)	(2,497,147)	(32,383)	-	-	(110,766)	-	-
25398	SO2 Emissions												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25399	Other Deferred Credits												
		D_SPLIT	S	(150,115)	-	-	(141,976)	(1,841)	-	-	(6,298)	-	-
		LABOR	SO	(15,811,596)	(6,433,592)	(1,205,434)	(5,670,598)	(90,806)	-	(805,825)	(1,032,358)	(572,983)	-
		P	SG	(6,846,119)	(6,846,119)	-	-	-	-	-	-	-	-
		P	SE	(1,892,222)	(1,892,222)	-	-	-	-	-	-	-	-
				(24,700,051)	(15,171,933)	(1,205,434)	(5,812,574)	(92,647)	-	(805,825)	(1,038,656)	(572,983)	-
190	Accumulated Deferred Income Taxes												
		D_SPLIT	S	100,469,432	-	-	95,022,301	1,232,236	-	-	4,214,895	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	20,860,610	8,487,989	1,590,357	7,481,353	119,802	-	1,063,143	1,362,014	755,951	-
		P	GPS	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	982,365	-	-	-	-	-	982,365	-	-	-
		P	TROJD	339,782	339,782	-	-	-	-	-	-	-	-
		P	SG	1,685,193	1,685,193	-	-	-	-	-	-	-	-
		P	SE	(1,025,618)	(1,025,618)	-	-	-	-	-	-	-	-
		LABOR	SNP	-	-	-	-	-	-	-	-	-	-
		D_SPLIT	SNPD	517,097	-	-	489,061	6,342	-	-	21,693	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				123,828,861	9,487,347	1,590,357	102,992,715	1,358,381	-	2,045,508	5,598,603	755,951	-
281	Accumulated Deferred Income Taxes												
		P	S	-	-	-	-	-	-	-	-	-	-
		PT	SG	0	0	0	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				0	0	0	-	-	-	-	-	-	-
282	Accumulated Deferred Income Taxes												
		GP	S	(686,948,122)	(303,504,021)	(162,558,173)	(201,754,872)	(2,638,025)	-	(3,259,149)	(10,971,298)	(2,262,584)	-
		CSS_SYS	CN	178	-	-	-	-	-	79	41	57	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		ACCMDIT	DITBAL	(94,748)	(43,698)	(26,535)	(24,377)	-	-	(70)	(68)	-	-
		PT	SNPD	-	-	-	-	-	-	-	-	-	-
		PT	CIAC	-	-	-	-	-	-	-	-	-	-
		C_Service	SNP	-	-	-	-	-	-	-	-	-	-
		P	SG-U	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(297,980)	(121,245)	(22,717)	(106,866)	(1,711)	-	(15,186)	(19,455)	(10,798)	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SE	(612,059)	(612,059)	-	-	-	-	-	-	-	-
		P	SG	(14,793,089)	(14,793,089)	-	-	-	-	-	-	-	-
				(702,745,820)	(319,074,112)	(162,607,426)	(201,886,115)	(2,639,736)	-	(3,274,326)	(10,990,780)	(2,273,325)	-
283	Accumulated Deferred Income Taxes												
		GP	S	(857,569)	(378,887)	(202,934)	(251,866)	(3,293)	-	(4,069)	(13,696)	(2,825)	-
		P	SG	(374,062)	(374,062)	-	-	-	-	-	-	-	-
		P	SE	(3,760,061)	(3,760,061)	-	-	-	-	-	-	-	-
		LABOR	SO	(5,850,816)	(2,380,643)	(446,051)	(2,098,310)	(33,601)	-	(298,182)	(382,007)	(212,023)	-
		GP	GPS	(1,856,397)	(820,184)	(439,294)	(545,219)	(7,129)	-	(8,807)	(29,649)	(6,114)	-
		LABOR	SNP	(201,026)	(81,796)	(15,326)	(72,095)	(1,154)	-	(10,245)	(13,125)	(7,285)	-
		P	TROJD	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
				(12,899,931)	(7,795,633)	(1,103,604)	(2,967,489)	(45,178)	-	(321,303)	(438,477)	(228,247)	-
TOTAL ACCUMULATED DEF INCOME TAX				(591,816,891)	(317,382,398)	(162,120,673)	(101,860,890)	(1,326,533)	-	(1,550,121)	(5,830,655)	(1,745,621)	-
255	Accumulated Investment Tax Credit												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC84	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC85	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC86	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC88	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC89	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC90	-	-	-	-	-	-	-	-	-	-
		LABOR	SG	0	0	0	0	0	-	0	0	0	-
				0	0	0	0	0	-	0	0	0	-
TOTAL RATE BASE DEDUCTIONS				**(1,051,299,856)**	**(735,185,068)**	**(176,846,795)**	**(121,266,217)**	**(1,629,242)**	**-**	**(3,932,696)**	**(9,000,082)**	**(3,439,756)**	**-**
108SP	Steam Prod Plant Accumulated Depr												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(197,516,132)	(197,516,132)	-	-	-	-	-	-	-	-
		P	SG	(189,153,855)	(189,153,855)	-	-	-	-	-	-	-	-
		P	SG	(660,308,520)	(660,308,520)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(64,099,365)	(64,099,365)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(1,111,077,872)	(1,111,077,872)	-	-	-	-	-	-	-	-
108NP	Nuclear Prod Plant Accumulated Depr												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108HP	Hydraulic Prod Plant Accum Depr												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(45,626,549)	(45,626,549)	-	-	-	-	-	-	-	-
		P	SG	(7,898,819)	(7,898,819)	-	-	-	-	-	-	-	-
		P	SG	(65,545,495)	(65,545,495)	-	-	-	-	-	-	-	-
		P	SG	(15,848,162)	(15,848,162)	-	-	-	-	-	-	-	-
		P	SG	7,257,618	7,257,618	-	-	-	-	-	-	-	-
				(127,661,407)	(127,661,407)	-	-	-	-	-	-	-	-
108OP	Other Production Plant - Accum Depr												

		P	S	(4,278)	(4,278)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	97,976,373	97,976,373	-	-	-	-	-	-	-	-
		P	SG	(310,938,608)	(310,938,608)	-	-	-	-	-	-	-	-
		P	SG	(9,594,946)	(9,594,946)	-	-	-	-	-	-	-	-
				(222,561,459)	(222,561,459)	-	-	-	-	-	-	-	-
108EP	Experimental Plant - Accum Depr												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL PRODUCTION PLANT DEPRECIATION				**(1,461,300,738)**	**(1,461,300,738)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
108TP	Transmission Plant Accumulated Depr												
		T_Split	S	-	-	-	-	-	-	-	-	-	-
		T_Split	SG	(91,521,571)	(1,953,733)	(89,567,838)	-	-	-	-	-	-	-
		T_Split	SG	(108,882,391)	(2,324,338)	(106,558,052)	-	-	-	-	-	-	-
		T_Split	SG	(310,453,638)	(6,627,328)	(303,826,310)	-	-	-	-	-	-	-
TOTAL TRANS PLANT ACCUM DEPR				**(510,857,599)**	**(10,905,398)**	**(499,952,201)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
108360	Land and Land Rights												
		D	S	(3,447,174)	-	-	(3,447,174)	-	-	-	-	-	-
				(3,447,174)	-	-	(3,447,174)	-	-	-	-	-	-
108361	Structures and Improvements												
		D	S	(8,815,872)	-	-	(8,815,872)	-	-	-	-	-	-
				(8,815,872)	-	-	(8,815,872)	-	-	-	-	-	-
108362	Station Equipment												
		D	S	(91,664,314)	-	-	(91,664,314)	-	-	-	-	-	-
				(91,664,314)	-	-	(91,664,314)	-	-	-	-	-	-
108363	Storage Battery Equipment												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108364	Poles, Towers & Fixtures												
		D	S	(273,837,267)	-	-	(273,837,267)	-	-	-	-	-	-
				(273,837,267)	-	-	(273,837,267)	-	-	-	-	-	-
108365	Overhead Conductors												
		D	S	(139,492,216)	-	-	(139,492,216)	-	-	-	-	-	-
				(139,492,216)	-	-	(139,492,216)	-	-	-	-	-	-
108366	Underground Conduit												
		D	S	(48,938,973)	-	-	(48,938,973)	-	-	-	-	-	-
				(48,938,973)	-	-	(48,938,973)	-	-	-	-	-	-
108367	Underground Conductors												
		D	S	(95,309,247)	-	-	(95,309,247)	-	-	-	-	-	-
				(95,309,247)	-	-	(95,309,247)	-	-	-	-	-	-
108368	Line Transformers												
		D	S	(248,014,579)	-	-	(248,014,579)	-	-	-	-	-	-
				(248,014,579)	-	-	(248,014,579)	-	-	-	-	-	-
108369	Services												
		D	S	(137,509,863)	-	-	(137,509,863)	-	-	-	-	-	-
				(137,509,863)	-	-	(137,509,863)	-	-	-	-	-	-
108370	Meters												
		C_Meter	S	(11,086,593)	-	-	-	-	-	-	(11,086,593)	-	-
				(11,086,593)	-	-	-	-	-	-	(11,086,593)	-	-
108371	Installations on Customers' Premises												
		DL	S	(2,176,777)	-	-	-	(2,176,777)	-	-	-	-	-
				(2,176,777)	-	-	-	(2,176,777)	-	-	-	-	-
108372	Leased Property												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108373	Street Lights												
		DL	S	(11,673,755)	-	-	-	(11,673,755)	-	-	-	-	-
				(11,673,755)	-	-	-	(11,673,755)	-	-	-	-	-
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	1,007,451	-	-	952,830	12,356	-	-	42,265	-	-
				1,007,451	-	-	952,830	12,356	-	-	42,265	-	-
TOTAL DISTRIBUTION PLANT DEPR				**(1,070,959,180)**	**-**	**-**	**(1,046,076,675)**	**(13,838,176)**	**-**	**-**	**(11,044,328)**	**-**	**-**
108GP	General Plant Accumulated Depr												
		D_SPLIT	S	(91,832,139)	-	-	(86,853,294)	(1,126,302)	-	-	(3,852,543)	-	-
		G-DGP	SG	(219,431)	(144,494)	(74,937)	-	-	-	-	-	-	-
		G-DGU	SG	(756,658)	(498,255)	(258,403)	-	-	-	-	-	-	-
		G-SG	SG	(32,434,949)	(13,467,223)	(18,967,725)	-	-	-	-	-	-	-
		B_Center	CN	(1,513,790)	-	-	-	-	-	(1,103,107)	-	(410,683)	-
		LABOR	SO	(29,016,198)	(11,806,423)	(2,212,118)	(10,406,235)	(166,640)	-	(1,478,786)	(1,894,502)	(1,051,494)	-
		P	SE	(441,759)	(441,759)	-	-	-	-	-	-	-	-
		G-SG	SG	(28,750)	(11,937)	(16,813)	-	-	-	-	-	-	-
		G-SG	SG	(705,944)	(293,113)	(412,831)	-	-	-	-	-	-	-
				(156,949,619)	(26,663,205)	(21,942,828)	(97,259,529)	(1,292,942)	-	(2,581,893)	(5,747,046)	(1,462,178)	-
108MP	Mining Plant Accumulated Depr.												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108MP	Less Centralia Situs Depreciation												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-

1081390	Accum Depr - Capital Lease												
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
1081399	Accum Depr - Capital Lease												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL GENERAL PLANT ACCUM DEPR				**(156,949,619)**	**(26,663,205)**	**(21,942,828)**	**(97,259,529)**	**(1,292,942)**	**-**	**(2,581,893)**	**(5,747,046)**	**(1,462,178)**	**-**
TOTAL ACCUM DEPR - PLANT IN SERVICE				**(3,200,067,136)**	**(1,498,869,341)**	**(521,895,028)**	**(1,143,336,204)**	**(15,131,118)**	**-**	**(2,581,893)**	**(16,791,374)**	**(1,462,178)**	**-**
111SP	Accum Prov for Amort-Steam												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
111GP	Accum Prov for Amort-General												
		D_SPLIT	S	(4,551,753)	-	-	(4,304,971)	(55,826)	-	-	(190,955)	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(1,053,024)	(428,466)	(80,280)	(377,652)	(6,048)	-	(53,666)	(68,753)	(38,160)	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				(5,604,777)	(428,466)	(80,280)	(4,682,623)	(61,874)	-	(53,666)	(259,708)	(38,160)	-
111HP	Accum Prov for Amort-Hydro												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(776,356)	(776,356)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(776,356)	(776,356)	-	-	-	-	-	-	-	-
111IP	Accum Prov for Amort-Intangible Plant												
		D_SPLIT	S	(114,464)	-	-	(108,258)	(1,404)	-	-	(4,802)	-	-
		LABOR	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SG	(127,466)	(51,865)	(9,718)	(45,714)	(732)	-	(6,496)	(8,322)	(4,619)	-
		P	SE	277,690	277,690	-	-	-	-	-	-	-	-
		LABOR	SG	(25,106,825)	(10,215,735)	(1,914,077)	(9,004,195)	(144,188)	-	(1,279,548)	(1,639,255)	(909,826)	-
		I-SG	SG	(29,380,021)	(19,370,311)	(10,009,710)	-	-	-	-	-	-	-
		I-SG	SG	(1,695,752)	(1,118,013)	(577,739)	-	-	-	-	-	-	-
		CSS_SYS	CN	(47,593,660)	-	-	-	-	-	(21,099,856)	(11,105,187)	(15,388,617)	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(5,711)	(5,711)	-	-	-	-	-	-	-	-
		LABOR	SO	(80,149,586)	(32,612,126)	(6,110,391)	(28,744,477)	(460,299)	-	(4,084,756)	(5,233,063)	(2,904,475)	-
				(183,895,794)	(63,096,069)	(18,621,635)	(37,902,645)	(606,623)	-	(26,470,656)	(17,990,629)	(19,207,537)	-
111IP	Less Non-Utility Plant												
		NUTIL	OTH	-	-	-	-	-	-	-	-	-	-
				(183,895,794)	(63,096,069)	(18,621,635)	(37,902,645)	(606,623)	-	(26,470,656)	(17,990,629)	(19,207,537)	-
111390	Accum Amtr - Capital Lease												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Lease Amtr			-	-	-	-	-	-	-	-	-	-
TOTAL ACCUM PROV FOR AMORTIZATION				**(190,276,927)**	**(64,300,891)**	**(18,701,915)**	**(42,585,267)**	**(668,497)**	**-**	**(26,524,322)**	**(18,250,338)**	**(19,245,696)**	**-**

Docket No. UE 374
Exhibit PAC/1404
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Functional Factors

February 2020

PacifiCorp
12 Months Ended June 2019
FUNCTIONAL FACTORS

Exhibit PAC/1404
Meredith/1

Internal Factors

Function	Description	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM	Total
CWC	Cash Working Capital	70.0365%	10.2008%	16.2903%	0.1134%	0.0000%	1.1915%	1.2663%	0.9012%	0.0000%	100.0000%
D_SPLIT	Distribution Split between Functions	0.0000%	0.0000%	96.6760%	0.0000%	0.0000%	0.0000%	3.3240%	0.0000%	0.0000%	100.0000%
GP	Gross Plant	47.2113%	23.0479%	27.6611%	0.0175%	0.0000%	0.4759%	1.2579%	0.3283%	0.0000%	100.0000%
IBT	Income Before Taxes	34.9754%	23.9756%	36.7436%	0.0557%	0.0000%	1.6491%	2.3722%	0.2284%	0.0000%	100.0000%
NP	Net Plant	46.0540%	26.1227%	26.4394%	-0.2072%	0.0000%	0.2517%	1.1740%	0.1654%	0.0000%	100.0000%
PT	Production / Transmission	65.8494%	34.1506%								100.0000%
PTD	Prod, Trans, Dist Plant	47.7801%	24.7796%	27.4404%							100.0000%
REVREQ	Revenue Requirement	63.7203%	14.3692%	18.8082%	0.0533%	0.0000%	0.9247%	1.3829%	0.7415%	0.0000%	100.0000%
T_SPLIT	Transmission Split	2.5107%	97.4893%								100.0000%
TD	Transmission / Distribution		47.4523%	52.5477%							100.0000%

External Factors

Function	Description	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM	Total
ACCMDIT	Deferred Income Tax - Balance	46.1199%	28.0064%	25.7283%	0.0000%	0.0000%	0.0737%	0.0717%	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%	72.8705%	0.0000%	27.1295%	0.0000%	100.0000%
BOOKDEPR	Book Depreciation	58.2131%	17.1130%	23.3504%	0.3771%	0.0000%	0.1436%	0.8028%	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%	29.8635%	53.8017%	16.3349%	0.0000%	100.0000%
CUST903	Cust. Records & Coll. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	59.0153%	9.6116%	31.3731%	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	99.9424%	5.7852%	31.7729%	0.0904%	0.0000%	-39.1897%	1.0281%	0.5706%	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%
DDSO2	Deferred Debits - System Overhead	39.7803%	7.6930%	37.6947%	0.5383%	0.0000%	4.7771%	6.1200%	3.3967%	0.0000%	100.0000%
DDSO6	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	83.6401%	16.3599%	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%	96.6760%	0.0000%	0.0000%	0.0000%	3.3240%	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	50.3966%	49.6034%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G	General Plant	21.1630%	35.2853%	40.7112%	0.0000%	0.0000%	1.4407%	1.3998%	0.0000%	0.0000%	100.0000%
G-DGP	General Plant - DGP Factor	65.8494%	34.1506%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G-DGU	General Plant - DGU Factor	65.8494%	34.1506%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G-SG	General Plant - SG Factor	41.5207%	58.4793%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G-SITUS	General Plant - SITUS Factor	0.0000%	30.5246%	67.1660%	0.0000%	0.0000%	0.0000%	2.3093%	0.0000%	0.0000%	100.0000%
I	Intangible Plant	47.2949%	17.8015%	14.6521%	0.0000%	0.0000%	7.0548%	7.8071%	5.3896%	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	65.9302%	34.0698%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-SITUS	Intangible Plant - SITUS Factor	319.9667%	-131.6059%	-85.4237%	0.0000%	0.0000%	0.0000%	-2.9371%	0.0000%	0.0000%	100.0000%
LABOR	Direct Labor Expense	40.6891%	7.6237%	35.8635%	0.5743%	0.0000%	5.0964%	6.5291%	3.6238%	0.0000%	100.0000%
MSS	Materials & Supplies	83.0294%	1.0274%	15.4132%	0.0000%	0.0000%	0.0000%	0.5299%	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	17.7673%	82.2308%	0.0019%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHDGU	Other Revenues - DGU Factor	17.7673%	82.2308%	0.0019%	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	17.7673%	82.2308%	0.0019%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSGR	Other Revenues - Rolled-In SG Factor	17.7673%	82.2308%	0.0019%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSITUS	Other Revenues - SITUS	-1.8974%	48.0979%	53.7995%	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	44.2545%	21.9467%	31.9019%	0.0119%	0.0000%	0.3546%	1.3199%	0.2106%	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	77.1698%	2.9346%	13.8048%	0.2211%	0.0000%	1.9617%	2.5132%	1.3949%	0.0000%	100.0000%
SCHMAP-SO	Schedule M Additions - Permanent-SO	78.5992%	2.7508%	12.9404%	0.2072%	0.0000%	1.8389%	2.3559%	1.3076%	0.0000%	100.0000%
SCHMAT	Schedule M Additions - Temporary	44.1845%	21.9871%	31.9403%	0.0115%	0.0000%	0.3512%	1.3174%	0.2081%	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	99.9987%	0.0002%	0.0008%	0.0000%	0.0000%	0.0001%	0.0001%	0.0001%	0.0000%	100.0000%
SCHMAT-SITUS	Schedule M Additions - Temporary-SITUS	191.7468%	-31.3943%	-57.7987%	-0.0207%	0.0000%	-0.1833%	-2.2194%	-0.1304%	0.0000%	100.0000%
SCHMAT-SNP	Schedule M Additions - Temporary-SNP	47.7637%	24.7836%	26.5328%	0.0000%	0.0000%	0.0037%	0.9139%	0.0024%	0.0000%	100.0000%
SCHMAT-SO	Schedule M Additions - Temporary-SO	40.7443%	7.7574%	35.7908%	0.5698%	0.0000%	5.0567%	6.4854%	3.5956%	0.0000%	100.0000%
SCHMD	Schedule M Deductions	63.0199%	15.4293%	20.0679%	0.0240%	0.0000%	0.5080%	0.6173%	0.3338%	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	49.3532%	28.5855%	24.4573%	-0.1274%	0.0000%	-1.1306%	-0.3340%	-0.8039%	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	63.0211%	15.4281%	20.0675%	0.0240%	0.0000%	0.5081%	0.6174%	0.3339%	0.0000%	100.0000%
SCHMDT-GPS	Schedule M Deductions - Temporary-GPS	47.7801%	24.7796%	26.5283%	0.0000%	0.0000%	0.0000%	0.9121%	0.0000%	0.0000%	100.0000%
SCHMDT-SG	Schedule M Deductions - Temporary-SG	101.0454%	-1.0454%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMDT-SITUS	Schedule M Deductions - Temporary-SITUS	132.2711%	3.4730%	-7.9326%	-0.2779%	0.0000%	-22.8529%	-2.9593%	-1.7213%	0.0000%	100.0000%
SCHMDT-SNP	Schedule M Deductions - Temporary-SNP	47.7801%	24.7796%	26.5283%	0.0000%	0.0000%	0.0000%	0.9121%	0.0000%	0.0000%	100.0000%
SCHMDT-SO	Schedule M Deductions - Temporary-SO	41.1112%	11.7514%	35.8093%	0.3984%	0.0000%	3.6037%	4.7684%	2.5576%	0.0000%	100.0000%
STEP_UP	Step-up Transformers	7.3598%	92.6402%	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	55.9785%	18.2272%	24.1253%	0.0236%	0.0000%	0.6398%	0.5641%	0.4414%	0.0000%	100.0000%

PacifiCorp
12 Months Ended June 2019
Tax Depreciation

	Total	Production	Transmission	Distribution	General	Mining
Total	969,960,513	507,405,388	165,765,680	191,230,186	105,559,259	-

Conversion to COS Functions	Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
Percent of GenPlant in Functions	100.0000%	33.6907%	10.4504%	40.5233%	0.2165%	0.0000%	5.8793%	5.1834%	4.0563%
Allocation of GenPlant to Functions	105,559,259	35,563,688	11,031,386	42,776,124	228,563	-	6,206,152	5,471,561	4,281,785
Assignment of Mining to Prod Functio	-	-							
Adjusted Totals	969,960,513	542,969,076	176,797,066	234,006,310	228,563	-	6,206,152	5,471,561	4,281,785
TAXDEPR FACTOR	100.0000%	55.9785%	18.2272%	24.1253%	0.0236%	0.0000%	0.6398%	0.5641%	0.4414%

PacifiCorp
12 Months Ended June 2019
Deferred Income Tax - Balance

		Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
Pacific Division										
Production	P	9,777,915	9,777,915	-	-	-	-	-	-	-
Transmission	T	8,964,074	-	8,964,074	-	-	-	-	-	-
Distribution	D	1,278,542	-	-	1,278,542	-	-	-	-	-
General	G	(748,972)	(158,505)	(264,277)	(304,916)	-	-	(10,791)	(10,484)	-
Mining Plant	P	4,407	4,407	-	-	-	-	-	-	-
Total Pacific Division		19,275,966	9,623,817	8,699,797	973,626	0	0	(10,791)	(10,484)	0
Utah Division										
Production	P	18,611,188	18,611,188	-	-	-	-	-	-	-
Transmission	T	20,683,211	-	20,683,211	-	-	-	-	-	-
Distribution	D	18,593,410	-	-	18,593,410	-	-	-	-	-
General	G	(909,654)	(192,510)	(320,974)	(370,331)	-	-	(13,106)	(12,733)	-
Mining Plant	P	9,054	9,054	-	-	-	-	-	-	-
Total Utah Division		56,987,209	18,427,732	20,362,237	18,223,079	0	0	(13,106)	(12,733)	0
PACIFICORP										
Prod / Other Prod	P	249,204,266	249,204,266	-	-	-	-	-	-	-
Cholla Unit 4	P	(23,473,392)	(23,473,392)	-	-	-	-	-	-	-
Gadsby Unit 4, 5 & 6	P	4,467,390	4,467,390	-	-	-	-	-	-	-
Hydro-PPL	P	21,982,344	21,982,344	-	-	-	-	-	-	-
Hydro-UPL	P	6,648,954	6,648,954	-	-	-	-	-	-	-
Transmission	T	178,123,314	-	178,123,314	-	-	-	-	-	-
Distribution	D	649,653,591	-	-	649,653,591	-	-	-	-	-
General/ Intangibles	G	17,901,804	3,788,554	6,316,705	7,288,047	-	-	257,915	250,583	-
Mining	P	2,017	2,017	-	-	-	-	-	-	-
WCA - CAEE 2007+	P	(2,206)	(2,206)	-	-	-	-	-	-	-
WCA - CAGE 2007+	PT	1,266,183,891	833,774,390	432,409,501	-	-	-	-	-	-
WCA - CAGW 2007+	PT	297,854,804	196,135,577	101,719,227	-	-	-	-	-	-
WCA_CAGW 2007+ -Marengo	P	(43,905,412)	(43,905,412)	-	-	-	-	-	-	-
WCA CAGW 2007+ -Goodnoe	P	0	-	-	-	-	-	-	-	-
WCA - General 2007+	G	128,707,004	27,238,229	45,414,653	52,398,224	-	-	1,854,306	1,801,592	-
WCA - JBG 2007+	P	108,364,789	108,364,789	-	-	-	-	-	-	-
OREGON EXTRA BOOK DEP	P	(106,317,436)	(106,317,436)	-	-	-	-	-	-	-
Total PC (Post Merger)		2,755,395,722	1,277,908,064	763,983,400	709,339,863	0	0	2,112,221	2,052,174	0
Total Deferred Taxes		2,831,658,897	1,305,959,614	793,045,434	728,536,567	0	0	2,088,325	2,028,957	0
ACCUMDIT FACTOR		100.00%	46.12%	28.01%	25.73%	0.00%	0.00%	0.07%	0.07%	0.00%

	Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
G	100.00%	21.1630%	35.2853%	40.7112%	0.0000%	0.0000%	1.4407%	1.3998%	0.0000%
P	100.00%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
D	100.00%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PT	100.00%	65.8494%	34.1506%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
T	100.00%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

PacifiCorp
12 Months Ended June 2019
General Plant

Description	Alloc. Factor	Funct.	Amount	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
Business Centers	CN	CUST	17,841	0	0	0	0	0	17,841	0	0
	SE	P	5,543	5,543	0	0	0	0	0	0	0
	SG	P	122,160	122,160	0	0	0	0	0	0	0
	SG	T	172,055	0	172,055	0	0	0	0	0	0
	SG	TD	-	0	0	0	0	0	0	0	0
General Plant	SO	DPW	-	0	0	0	0	0	0	0	0
	SO	PTD	281,213	134,364	69,683	74,601	0	0	0	2,565	0
	SO	TD	-	0	0	0	0	0	0	0	0
	SO	P	-	0	0	0	0	0	0	0	0
SSGCT	SG	DPW	-	0	0	0	0	0	0	0	0
	SITUS	DPW	228,135	0	0	220,552	0	0	0	7,583	0
	SITUS	P	-	0	0	0	0	0	0	0	0
	SITUS	TD	411,382	0	195,210	208,987	0	0	0	7,186	0
Total-CUST			17,842	0	0	0	0	0	17,842	0	0
Total-TD			411,383	0	195,211	208,987	0	0	0	7,186	0
Total-PTD			281,214	134,364	69,684	74,601	0	0	0	2,565	0
Total-DPW			228,136	0	0	220,553	0	0	0	7,583	0
Total-SSGCH			0	0	0	0	0	0	0	0	0
Total-SSGCT			0	0	0	0	0	0	0	0	0
Total-G-SG			294,215	122,160	172,055	0	0	0	0	0	0
Total-UT			5,543	5,543	0	0	0	0	0	0	0
Total-G-Situs			639,518	0	195,210	429,539	0	0	0	14,769	0
Total-SO			281,213	134,364	69,683	74,601	0	0	0	2,565	0
Total-General Plant			1,238,330	262,067	436,948	504,140	0	0	17,841	17,334	0
G-SG Factor			100.00%	41.5207%	58.4793%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
UT Factor			100.00%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
G-SITUS Factor			100.00%	0.0000%	30.5246%	67.1660%	0.0000%	0.0000%	0.0000%	2.3093%	0.0000%
SO Factor			100.00%	47.7801%	24.7796%	26.5283%	0.0000%	0.0000%	0.0000%	0.9121%	0.0000%
G Allocator			100.00%	21.1630%	35.2853%	40.7112%	0.0000%	0.0000%	1.4407%	1.3998%	0.0000%
Total Gen. Plant			1,238,330								
Mining			97,975	5,543	5,543	0	0	0	0	0	0
Total		P	1,336,305								

Functional Allocators:

	Funct.	Amount	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
	P	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	T	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	TD	100.00%	0.00%	47.45%	50.80%	0.00%	0.00%	0.00%	1.75%	0.00%
	CUST	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
	DPW	100.00%	0.00%	0.00%	96.68%	0.00%	0.00%	0.00%	3.32%	0.00%
	PTD	100.00%	47.78%	24.78%	26.53%	0.00%	0.00%	0.00%	0.91%	0.00%
	GP	100.00%	46.61%	25.07%	26.85%	0.00%	0.00%	0.26%	1.04%	0.17%

PacifiCorp
12 Months Ended June 2019
FERC FORM 1 Funtionalization Factors

Factor	Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM
PLANT	26,014,894	12,429,934	6,446,374	6,901,301				237,285	0	0
UNCLASSIFIED PLAN	0								0	0
TOTAL PLANT	26,014,894	12,429,934	6,446,374	6,901,301		0	0	237,285	0	0
PLANT %										
P	100.0000%	100.0000%								
T	100.0000%		100.0000%							
CUST							100.0000%			
DPW	100.0000%			96.6760%				3.3240%		
PTD	100.0000%	47.7801%	24.7796%	26.5283%				0.9121%	0.0000%	0.0000%
PT	100.0000%	65.8494%	34.1506%							
TD	100.0000%		47.4523%	50.8010%				1.7467%		

Source: Oregon Results of Operations

Factor	Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM
Material & Supplies	76,528,714	63,541,336	786,256	11,795,559				405,563	0	0
Material & Supplies %	100.0000%	83.0294%	1.0274%	15.4132%		0.0000%	0.0000%	0.5299%	0.0000%	0.0000%

Source: FERC Form 1 (2018) - pg. 227

Meter Percent of Total Distribution		
Account 370	237,285	3.32%
Total Distribution	7,138,587	100.00%

Source: Oregon Results of Operations

Factor	Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM
FERC (mWh)	32,352,108	16,304,361	16,047,747	0		0	0	0	0	0
FERC %	100.0000%	50.3966%	49.6034%	0.0000%		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Source: 2018 FERC reporting requirment No. 582

PacifiCorp
12 Months Ended June 2019
Summary of FERC Accounts 901 - 910 by Functional Groups

Line No.	Description	FERC Account	Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
1	Supervision	901	2,690						803	1,447	439
2	Meter Reading	902	17,222								
3	Cust. Records & Coll. Exp.	903	48,362						28,541	4,648	15,173
4	Uncollectible Accounts	904	13,337								
5	Misc. Customer Acct. Exp.	905	439						-	-	439
6	Supervision	907	0								
7	Customer Assistance Exp.	908	92,189								
8	Information & Instructional Ex	909	7,087								
9	Misc. cust. Serv. & Inform. Exp	910	16								
10	Total		181,343								

Account	Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
CUST901	100.0000%						29.8635%	53.8017%	16.3349%
CUST903	100.0000%						59.0153%	9.6116%	31.3731%
CUST905	100.0000%						-	-	100.0000%

PacifiCorp
12 Months Ended June 2019
Gross Plant
(In 000's)

Description	Alloc. Factor	Funct.	Amount	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM
Production Plant		P	12,429,934	12,429,934	0	0	0	0	0	0	0	0
Transmission Plant		T	6,446,374	0	6,446,374	0	0	0	0	0	0	0
Distribution Plant		DPW	7,138,587	0	0	6,901,301	0	0	0	237,285	0	0
Mining	SE	P	97,975	97,975	0	0	0	0	0	0	0	0
General Plant				0	0	0	0	0	0	0	0	0
Business Centers	CN	B_Center	17,841	0	0	0	0	0	13,001	0	4,840	0
Utah Mine	SE	P	5,543	5,543	0	0	0	0	0	0	0	0
	SG	P	122,160	122,160	0	0	0	0	0	0	0	0
	SG	T	172,055	0	172,055	0	0	0	0	0	0	0
	SO	DPW	0	0	0	0	0	0	0	0	0	0
	SG	DPW	0	0	0	0	0	0	0	0	0	0
General Plant	SITUS	DPW	228,135	0	0	220,552	0	0	0	7,583	0	0
General Plant	SITUS	P	0	0	0	0	0	0	0	0	0	0
General Plant	SITUS	TD	411,382	0	195,210	208,987	0	0	0	7,186	0	0
Total General Plant			957,117	127,704	367,265	429,539	0	0				0
Intangible Plant												
	CN	CSS_SYS	126,738	0	0	0	0	0	56,187	29,572	40,979	0
	SE	P	7	7	0	0	0	0	0	0	0	0
	SG	PTD	0	0	0	0	0	0	0	0	0	0
	SG	T	60,410	0	60,410	0	0	0	0	0	0	0
	SG	P	116,902	116,902	0	0	0	0	0	0	0	0
	SG-U	P	9,951	9,951	0	0	0	0	0	0	0	0
	SO	CUST	3,071	0	0	0	0	0	1,362	717	993	0
	SO	C_METER	2,908	0	0	0	0	0	0	2,908	0	0
	SO	C_BILLING	2,629	0	0	0	0	0	2,629	0	0	0
	SO	DPW	32,715	0	0	31,627	0	0	0	1,087	0	0
	SO	P	30,030	30,030	0	0	0	0	0	0	0	0
	SO	PTD	268,917	128,489	66,636	71,339	0	0	0	2,453	0	0
	SO	TD	41,887	0	19,876	21,279	0	0	0	732	0	0
	SO	LABOR	0	0	0	0	0	0	0	0	0	0
Total Intangible Plant			696,165	285,379	146,923	124,245	0	0	60,178	37,469	41,972	0
Total Gross Plant			27,766,151	12,940,991	6,960,562	7,455,085	0	0	73,179	289,522	46,812	0
GP Factor			100.0000%	46.6071%	25.0685%	26.8495%	0.0000%	0.0000%	0.2636%	1.0427%	0.1686%	0.0000%

Functional Allocators:			Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM
	P	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	T	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	TD	100.0000%	0.0000%	47.4523%	50.8010%	0.0000%	0.0000%	0.0000%	1.7467%	0.0000%	0.0000%
	B_Center	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	72.8705%	0.0000%	27.1295%	0.0000%
	CSS_SYS	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	44.3333%	23.3333%	32.3333%	0.0000%
	CUST	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	44.3333%	23.3333%	32.3333%	0.0000%
	C_BILLING	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%
	C_METER	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
	C_SERVICE	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%
	DPW	100.0000%	0.0000%	0.0000%	96.6760%	0.0000%	0.0000%	0.0000%	3.3240%	0.0000%	0.0000%
	PTD	100.0000%	47.7801%	24.7796%	26.5283%	0.0000%	0.0000%	0.0000%	0.9121%	0.0000%	0.0000%
	LABOR	100.0000%	40.6891%	7.6237%	35.8635%	0.5743%	0.0000%	5.0964%	6.5291%	3.6238%	0.0000%

PacifiCorp
CSS System Allocation Factor
Business Center Allocation Factor
12 Months Ended June 2019

Description	Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM
Customer Service System (CSS)										
CSS_SYS	100.0000%						44.3333%	23.3333%	32.3333%	

The size is based on the lines of code; regardless of type of code.
Some Additional Code related to general use and system maintenance is assumed to be shared by all functions.

Description	Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM
Business Center Expenses										
Wasatch Business Center -										
6/2019	6,131,332						6,130,920		412	
6/2019 Support	1,617,400						808,700		808,700	
Portland Business Center -										
6/2019	7,425,555						4,384,776		3,040,779	
6/2019 Support	1,166,629						583,314		583,314	
Total	$ 16,340,916						$ 11,907,711		$ 4,433,205	
B_CENTER	100.0000%						72.8705%		27.1295%	

PacifiCorp
Oregon Labor Costs
12 Months Ended June 2019

Function	FERC Form 1	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM
P	52,548,338	52,548,338	-	-	-	-	-	-	-	-
T	7,962,224	-	7,962,224	-	-	-	-	-	-	-
DPW	4,048,661	-	-	3,914,084	-	-	-	134,577	-	-
D	42,536,146	-	-	42,536,146	-	-	-	-	-	-
DL	743,829	-	-	-	743,829	-	-	-	-	-
C_Meter	6,897,607	-	-	-	-	-	-	6,897,607	-	-
CUST901	713,637	-	-	-	-	-	213,117	383,948	116,572	-
CUST903	10,823,848	-	-	-	-	-	6,387,729	1,040,343	3,395,776	-
CUST905	-	-	-	-	-	-	-	-	-	-
C_Service	1,181,199	-	-	-	-	-	-	-	1,181,199	-
Step_Up	2,063,887	151,898	1,911,989	-	-	-	-	-	-	-
Total Labor	129,519,375	52,700,236	9,874,212	46,450,230	743,829	-	6,600,845	8,456,476	4,693,547	-
LABOR	100.0000%	40.6891%	7.6237%	35.8635%	0.5743%	-	5.0964%	6.5291%	3.6238%	-

Functional Allocation Factor		Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM
C_METER	100.0000%	-	-	-	-	-	-	100.000%	-	-
C_Service	100.0000%	-	-	-	-	-	-	-	100.000%	-
CUST901	100.0000%	-	-	-	-	-	29.863%	53.802%	16.335%	-
CUST903	100.0000%	-	-	-	-	-	59.015%	9.612%	31.373%	-
CUST905	100.0000%	-	-	-	-	-	-	-	100.000%	-
D	100.0000%	-	-	100.000%	-	-	-	-	-	-
DL	100.0000%	-	-	-	100.000%	-	-	-	-	-
DPW	100.0000%	-	-	96.676%	-	-	-	3.324%	-	-
P	100.0000%	100.000%	-	-	-	-	-	-	-	-
STEP_UP	100.0000%	7.3598%	92.6402%	-	-	-	-	-	-	-
T	100.0000%	-	100.0000%	-	-	-	-	-	-	-

PacifiCorp
12 Months Ended June 2019
Step-up Transformer Factor

Asset Class 35340 = GSU and Assoc Equip

Class	Description	Acq.value	Accum.dep.	Book Value
35300	Station Equipment	66,245,416	-29,912,604	36,332,812
35301	Transformers	428,439,531	-109,903,842	318,535,689
35303	Static Var Unit	46,344,465	-7,770,165	38,574,300
35305	Synchronous Condens.	16,898,297	-2,780,574	14,117,724
35307	Regulators	1,446,450	-481,441	965,009
35309	Circuit Breakers	258,489,343	-54,478,839	204,010,505
35311	Capacitor Bank	116,320,196	-24,412,137	91,908,059
35313	Metal Clad Switchgr.	7,240,294	-1,589,971	5,650,322
35315	Switching Equipment	114,440,717	-28,499,957	85,940,760
35317	Structures & Foundn.	379,393,585	-71,063,364	308,330,221
35319	Relay & Control Eqp.	246,281,895	-45,725,863	200,556,032
35321	Storage Battery Eqp.	11,890,143	-2,049,516	9,840,627
35323	Auxiliary Power Eqp.	7,008,352	-1,200,855	5,807,497
35325	Grounding System	51,789,331	-9,122,317	42,667,014
35327	Bus,Wire,Cable&Insul	251,754,907	-52,975,189	198,779,718
35329	Station Lighting	2,523,889	-708,385	1,815,504
35331	Mobile Substation	4,653,349	-1,125,327	3,528,022
35333	Mobile Circuit Swtcr	232,902	-85,718	147,184
35339	Fire Protection Sys.	105,216	-37,721	67,495
35340	GSU and Assoc Equip	164,162,068	-38,229,012	125,933,056
35341	Supervsry Cont Equip	21,575,978	-5,172,092	16,403,887
35342	Sprvsry Cntl Eqp 353	718,779	-240,288	478,492
35343	Dispatch Comp. Sys.	23,403	-10,131	13,272
35344	Dsptch Comp Sys(353)	18,340	-6,756	11,584
35345	Dispatch Hardware	952,147	-351,258	600,888
35347	Dsptch Strg Btry Eqp	8,490	-3,446	5,044
35348	Dsptch Strg Btry 353	59,785	-22,151	37,634
35349	Dispatch Time Stdrd	15,975	-5,350	10,625
35350	Dsptch Time Std(353)	37,956	-15,324	22,632
	PacifiCorp Total	2,199,071,199	(487,979,592)	1,711,091,606

		$	Percent	
35340	Step-up Transformers included in Acct 353	125,933,056	7.3598%	Production
	Acct 353 other than step-up transformers	1,585,158,550	92.6402%	Transmission
35300-35399	Account 353 Station Equipment	1,711,091,606	100.0000%	

PacifiCorp
12 Months Ended June 2019
Depreciation Expense

Function	Amount	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM
CUST	1,040	-	-	-	-	-	1,040	-	-	-
DPW	155,473	-	-	150,305	-	-	-	5,168	-	-
DL	2,732	-	-	-	2,732	-	-	-	-	-
G-DGP	0	0	0	0	-	-	-	0	-	-
G-DGU	655	431	224	-	-	-	-	-	-	-
G-SG	9,499	-	4,508	4,826	-	-	-	166	-	-
G-SITUS	14,773	-	4,510	9,923	-	-	-	341	-	-
P	413,910	413,910	-	-	-	-	-	-	-	-
PTD	15,567	7,438	3,857	4,130	-	-	-	142	-	-
T	110,893	-	110,893	-	-	-	-	-	-	-
Book Depreciation	724,544	421,779	123,992	169,184	2,732	-	1,040	5,817	-	-
BookDepr Factor	100.00%	58.2131%	17.1130%	23.3504%	0.3771%	0.0000%	0.1436%	0.8028%	0.0000%	0.0000%

P	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
T	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DPW	100.0000%	0.0000%	0.0000%	96.6760%	0.0000%	0.0000%	0.0000%	3.3240%	0.0000%	0.0000%
DL	100.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
G-DGP	100.0000%	47.7801%	24.7796%	26.5283%	0.0000%	0.0000%	0.0000%	0.9121%	0.0000%	0.0000%
G-DGU	100.0000%	65.8494%	34.1506%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
G-SG	100.0000%	0.0000%	47.4523%	50.8010%	0.0000%	0.0000%	0.0000%	1.7467%	0.0000%	0.0000%
G-SITUS	100.0000%	0.0000%	30.5246%	67.1660%	0.0000%	0.0000%	0.0000%	2.3093%	0.0000%	0.0000%
CUST	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%
PTD	100.0000%	47.7801%	24.7796%	26.5283%	0.0000%	0.0000%	0.0000%	0.9121%	0.0000%	0.0000%
TD	100.0000%	0.0000%	47.4523%	50.8010%	0.0000%	0.0000%	0.0000%	1.7467%	0.0000%	0.0000%
G	100.0000%	21.1630%	35.2853%	40.7112%	0.0000%	0.0000%	1.4407%	1.3998%	0.0000%	0.0000%

PacifiCorp
12 Months Ended June 2019
Deferred Debits / Reg Assets

	Pri-Acct	Factor	Function	Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
RA-SE	182M	SE	P	188,481	188,481	0	0	0	0	0	0	0
RA-SG	182M	SG	P	3,449	3,449	0	0	0	0	0	0	0
RA-SGCT	182M	SGCT	P	0	0	0	0	0	0	0	0	0
RA-SG-P	182M	SG-P	P	0	0	0	0	0	0	0	0	0
RA-SO	182M	SO	DMSC	3,647	0	0	3,647	0	0	0	0	0
RA-SO	182M	SO	LABOR	429,168	174,625	32,719	153,915	2,465	0	21,872	28,021	15,552
RA-SO	182M	SO	ESD	25,044	7,513	2,504	15,026	0	0	0	0	0
RA-SO	182M	SO	P	0	0	0	0	0	0	0	0	0
RA-SO	182M	SO	TD	0	0	0	0	0	0	0	0	0
RA-OTHER	182M	OTHER	CUST	109,206	0	0	0	0	0	109,206	0	0
RA-OTHER	182M	OTHER	DMSC	19,834	0	0	19,834	0	0	0	0	0
RA-OTHER	182M	OTHER	LABOR	6,417	2,611	489	2,301	37	0	327	419	233
RA-OTHER	182M	OTHER	P	(33,979)	-33,979	0	0	0	0	0	0	0
RA-OTHER	182M	OTHER	DPW	0	0	0	0	0	0	0	0	0
RA-OTHER	182M	OTHER	PTD	2,334	1,115	578	619	0	0	0	21	0
RA-OTHER	182M	OTHER	ESD	0	0	0	0	0	0	0	0	0
RA-TROJD	182M	TROJD	P	0	0	0	0	0	0	0	0	0
RA-TROJP	182M	TROJP	P	0	0	0	0	0	0	0	0	0
RA-SITUS	182M	SITUS	DMSC	61	0	0	61	0	0	0	0	0
RA-SITUS	182M	SITUS	LABOR	(691)	-281	-53	-248	-4	0	-35	-45	-25
RA-SITUS	182M	SITUS	P	(3,502)	-3,502	0	0	0	0	0	0	0
RA-SITUS	182M	SITUS	PTD	0	0	0	0	0	0	0	0	0
RA-SITUS	182M	SITUS	ESD	(2,013)	-604	-201	-1,208	0	0	0	0	0
RA-SITUS	182M	SITUS	CUST	1,756	0	0	0	0	0	1,756	0	0
	Total-SO			457,859	182,138	35,223	172,589	2,465	-	21,872	28,021	15,552
	Total SITUS			(4,390)	(4,387)	(254)	(1,395)	(4)	-	1,720	(45)	(25)
	Total RA			749,211	339,427	36,037	193,948	2,498	-	133,126	28,416	15,760
	DDSO2 FACTOR			100.00%	39.7803%	7.6930%	37.6947%	0.5383%	0.0000%	4.7771%	6.1200%	3.3967%
	DDS2 FACTOR			100.00%	99.9424%	5.7852%	31.7729%	0.0904%	0.0000%	-39.1897%	1.0281%	0.5706%

PacifiCorp
12 Months Ended June 2019
Deferred Debits / Reg Assets

	Pri-Acct	Factor	Function	Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
DD-SE	186M	SE	P	1,648	1,648	0	0	0	0	0	0	0
DD-SG	186M	SG	P	58,242	58,242	0	0	0	0	0	0	0
DD-SG	186M	SG	T	11,392	0	11,392	0	0	0	0	0	0
DD-SO	186M	SO	DMSC	300	0	0	300	0	0	0	0	0
DD-OTHER	186M	OTHER	DMSC	2,595	0	0	2,595	0	0	0	0	0
DD-OTHER	186M	OTHER	PTD	128	61	32	34	0	0	0	1	0
DD-OTHER	186M	OTHER	T	1,370	0	1,370	0	0	0	0	0	0
	Total SITUS			-	-	-	-	-	-	-	-	-
	Total SG			69,634	58,242	11,392	-	-	-	-	-	-
	Total-SO			300	-	-	300	-	-	-	-	-
	Total-DD			75,674	59,951	12,794	2,928	-	-	-	1	-
	DEFSG FACTOR			100.00%	83.6401%	16.3599%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Major Adjustment											
	1998 Early Retirement		LABOR	-	0	0	0	0	0	0	0	0
	1999 Early Retirement		LABOR	-	0	0	0	0	0	0	0	0
	Transition Planning		PTD	-	0	0	0	0	0	0	0	0
	Environmental Clean-up		ESD	-	0	0	0	0	0	0	0	0
	Y2K		PTD	-	0	0	0	0	0	0	0	0
	Subtotal Major Adjustments			-	-	-	-	-	-	-	-	-
	Total 186M SO			300	-	-	300	-	-	-	-	-
	Total 182 &186			824,885	399,378	48,830	196,877	2,498	-	133,126	28,417	15,760

	Total		Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
DMSC		100.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DPW		100.0000%	0.0000%	0.0000%	96.6760%	0.0000%	0.0000%	0.0000%	3.3240%	0.0000%
CUST		100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
ESD		100.0000%	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
GP		100.0000%	46.6071%	25.0685%	26.8495%	0.0000%	0.0000%	0.2636%	1.0427%	0.1686%
LABOR		100.0000%	40.6891%	7.6237%	35.8635%	0.5743%	0.0000%	5.0964%	6.5291%	3.6238%
P		100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PT		100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PTD		100.0000%	47.7801%	24.7796%	26.5283%	0.0000%	0.0000%	0.0000%	0.9121%	0.0000%
T		100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
TAXDEPR		100.0000%	55.9785%	18.2272%	24.1253%	0.0236%	0.0000%	0.6398%	0.5641%	0.4414%
TD		100.0000%	0.0000%	47.4523%	50.8010%	0.0000%	0.0000%	0.0000%	1.7467%	0.0000%
	1	2	3	4	5	6	7	8	9	10

PacifiCorp
12 Months Ended June 2019
Intangible Plant
(In 000's)

Alloc. Factor	Funct.	Amount	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
CN	CSS_SYS	126,738	0	0	0	0	0	56,187	29,572	40,979
CN	CUST	8,500	0	0	0	0	0	3,768	1,983	2,748
CN	C_METER	31,019	0	0	0	0	0	0	31,019	0
CN	C_SERVICE	4,132	0	0	0	0	0	0	0	4,132
SE	P	7	7	0	0	0	0	0	0	0
SG	PTD	-	0	0	0	0	0	0	0	0
SG	T	60,410	0	60,410	0	0	0	0	0	0
SG	P	116,902	116,902	0	0	0	0	0	0	0
SG-U	P	9,951	9,951	0	0	0	0	0	0	0
SG-P	P	175,395	175,395	0	0	0	0	0	0	0
SO	CUST	3,071	0	0	0	0	0	1,362	717	993
SO	C_METER	2,908	0	0	0	0	0	0	2,908	0
SO	C_BILLING	2,629	0	0	0	0	0	2,629	0	0
SO	DPW	32,715	0	0	31,627	0	0	0	1,087	0
SO	P	30,030	30,030	0	0	0	0	0	0	0
SO	PTD	268,917	128,489	66,636	71,339	0	0	0	2,453	0
SO	T	1,240	0	1,240	0	0	0	0	0	0
SO	TD	41,887	0	19,876	21,279	0	0	0	732	0
SO	LABOR	-	0	0	0	0	0	0	0	0
SITUS	DPW	158	0	0	152	0	0	0	5	0
SITUS	PTD	-	0	0	0	0	0	0	0	0
SITUS	P	(32,081)	(32,081)	0	0	0	0	0	0	0
SITUS	T	5,337	0	5,337	0	0	0	0	0	0
SITUS	TD	16,560	0	7,858	8,413	0	0	0	289	0
Total-DGP		175,395	175,395	-	-	-	-	-	-	-
Total-DGU		9,951	9,951	-	-	-	-	-	-	-
Total-SG		177,312	116,902	60,410	-	-	-	-	-	-
Total-SITUS		(10,026)	(32,081)	13,195	8,565	-	-	-	294	-
Total-Intangible		906,424	428,693	161,357	132,810	-	-	63,946	70,765	48,852
I-SG FACTOR		100.00%	65.9302%	34.0698%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
I-Situs FACTOR		100.00%	319.9667%	-131.6059%	-85.4237%	0.0000%	0.0000%	0.0000%	-2.9371%	0.0000%
I FACTOR		100.00%	47.2949%	17.8015%	14.6521%	0.0000%	0.0000%	7.0548%	7.8071%	5.3896%

Functional Allocators:		Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
P	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
T	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TD	100.00%	0.00%	47.45%	50.80%	0.00%	0.00%	0.00%	1.75%	0.00%
CSS_SYS	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	44.33%	23.33%	32.33%
C_BILLING	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
C_METER	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
C_SERVICE	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
CSS_SYS	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	44.33%	23.33%	32.33%
CUST	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	44.33%	23.33%	32.33%
DPW	100.00%	0.00%	0.00%	96.68%	0.00%	0.00%	0.00%	3.32%	0.00%
PTD	100.00%	47.78%	24.78%	26.53%	0.00%	0.00%	0.00%	0.91%	0.00%
LABOR	100.00%	40.69%	7.62%	35.86%	0.57%	0.00%	5.10%	6.53%	3.62%

PacifiCorp
12 Months Ended June 2019
Schedule M

	Primary Account	PITA Factor	Function	Amount	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
							ADDITIONS					
SCHMAP-SCHMDEXP	SCHMAP	SCHMDEXP	LABOR	129	52.61	9.86	46.37	0.74	-	6.59	8.44	4.69
SCHMAP-SE	SCHMAP	SE	P	58	58.13	-	-	-	-	-	-	-
SCHMAP-SO	SCHMAP	SO	P	1,516	1,515.63	-	-	-	-	-	-	-
SCHMAP-SO	SCHMAP	SO	LABOR	856	348.13	65.23	306.85	4.91	-	43.60	55.86	31.01
SCHMAP-SO	SCHMAP	SO	PTD	-	-	-	-	-	-	-	-	-
	Total-SO			2,371	1,864	65	307	5	-	44	56	31
	Total SCHMAP			2,559	1,974	75	353	6	-	50	64	36
	SCHMAP-SO			100.00%	78.5992%	2.7508%	12.9404%	0.2072%	0.0000%	1.8389%	2.3559%	1.3076%
	SCHMAP FACTOR			100.00%	77.1698%	2.9346%	13.8048%	0.2211%	0.0000%	1.9617%	2.5132%	1.3949%
SCHMAT-CIAC	SCHMAT	CIAC	DPW	103,001	-	-	99,577	-	-	-	3,424	-
SCHMAT-BADDEBT	SCHMAT	BADDEBT	CUST	397	-	-	-	-	-	397	-	-
SCHMAT-SCHMDEXP	SCHMAT	SCHMDEXP	GP	984,008	458,617	246,676	264,202	-	-	2,593	10,260	1,659
SCHMAT-GPS	SCHMAT	GPS	GP	(591)	(275)	(148)	(159)	-	-	(2)	(6)	(1)
SCHMAT-SE	SCHMAT	SE	LABOR	1	0	0	0	0	-	0	0	0
SCHMAT-SE	SCHMAT	SE	P	35,251	35,251	-	-	-	-	-	-	-
SCHMAT-SG	SCHMAT	SG	DPW	-	-	-	-	-	-	-	-	-
SCHMAT-SG	SCHMAT	SG	P	(404)	(404)	-	-	-	-	-	-	-
SCHMAT-SG	SCHMAT	SG	T	-	-	-	-	-	-	-	-	-
SCHMAT-SGCT	SCHMAT	SGCT	P	-	-	-	-	-	-	-	-	-
SCHMAT-SNP	SCHMAT	SNP	GP	585	273	147	157	-	-	2	6	1
SCHMAT-SNP	SCHMAT	SNP	PTD	41,262	19,715	10,224	10,946	-	-	-	376	-
SCHMAT-SNPD	SCHMAT	SNPD	DPW	2,099	-	-	2,029	-	-	-	70	-
SCHMAT-SO	SCHMAT	SO	DMSC	-	-	-	-	-	-	-	-	-
SCHMAT-SO	SCHMAT	SO	LABOR	24,189	9,842	1,844	8,675	139	-	1,233	1,579	877
SCHMAT-SO	SCHMAT	SO	PTD	190	91	47	50	-	-	-	2	-
SCHMAT-OTHER	SCHMAT	OTHER	DMSC	(6,090)	-	-	(6,090)	-	-	-	-	-
SCHMAT-OTHER	SCHMAT	OTHER	GP	(15,034)	(7,007)	(3,769)	(4,037)	-	-	(40)	(157)	(25)
SCHMAT-OTHER	SCHMAT	OTHER	P	(15,790)	(15,790)	-	-	-	-	-	-	-
SCHMAT-OTHER	SCHMAT	OTHER	PTD	44,976	21,490	11,145	11,931	-	-	-	410	-
SCHMAT-OTHER	SCHMAT	OTHER	CUST	51	-	-	-	-	-	51	-	-
SCHMAT-TROJD	SCHMAT	TROJD	P	(51)	(51)	-	-	-	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	DMSC	-	-	-	-	-	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	DPW	(1,289)	-	-	(1,246)	-	-	-	(43)	-
SCHMAT-SITUS	SCHMAT	SITUS	ESD	104	31	10	62	-	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	GP	-	-	-	-	-	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	LABOR	(185)	(75)	(14)	(66)	(1)	-	(9)	(12)	(7)
SCHMAT-SITUS	SCHMAT	SITUS	P	13,031	13,031	-	-	-	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	PTD	(6,510)	(3,111)	(1,613)	(1,727)	-	-	-	(59)	-
SCHMAT-SITUS	SCHMAT	SITUS	T	-	-	-	-	-	-	-	-	-
	Total-SG			(404)	(404)	-	-	-	-	-	-	-
	Total-SE			35,252	35,251	0	0	0	-	0	0	0
	Total-SNP			41,847	19,988	10,371	11,103	-	-	2	382	1
	Total-SITUS			5,151	9,876	(1,617)	(2,977)	(1)	-	(9)	(114)	(7)
	Total SO			24,379	9,933	1,891	8,725	139	-	1,233	1,581	877
	Total-SCHMAT			1,203,201	531,628	264,549	384,306	138	-	4,225	15,851	2,503
	SCHMAT-SG			100.00%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	SCHMAT-SE			100.00%	99.9987%	0.0002%	0.0008%	0.0000%	0.0000%	0.0001%	0.0001%	0.0001%
	SCHMAT-SNP			100.00%	47.7637%	24.7836%	26.5328%	0.0000%	0.0000%	0.0037%	0.9139%	0.0024%
	SCHMAT-SITUS			100.00%	191.7468%	-31.3943%	-57.7987%	-0.0207%	0.0000%	-0.1833%	-2.2194%	-0.1304%
	SCHMAT-SO			100.00%	40.7443%	7.7574%	35.7908%	0.5698%	0.0000%	5.0567%	6.4854%	3.5956%
	SCHMAT FACTOR			100.00%	44.1845%	21.9871%	31.9403%	0.0115%	0.0000%	0.3512%	1.3174%	0.2081%
SCHMAF-DGP	SCHMAF	DGP	P	-	-	-	-	-	-	-	-	-
SCHMAF-TROJP	SCHMAF	TROJP	P	-	-	-	-	-	-	-	-	-
	Total-SCHMAF			-	-	-	-	-	-	-	-	-
	SCHMAF FACTOR			0.00%								

Exhibit PAC/1404
Meredith/16

PacifiCorp
12 Months Ended June 2019
Schedule M

	Primary Account	PITA Factor	Function	Amount	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
	Total-SCHMA			1,205,760	533,602	264,624	384,660	144	-	4,276	15,915	2,539
	SCHMA FACTOR			100.00%	44.2545%	21.9467%	31.9019%	0.0119%	0.0000%	0.3546%	1.3199%	0.2106%
						DEDUCTIONS						
SCHMDP-SCHMDEXP	SCHMDP	SCHMDEXP	LABOR	(19)	(7.88)	(1.48)	(6.94)	(0.11)	-	(0.99)	(1.26)	(0.70)
SCHMDP-SE	SCHMDP	SE	P	-	-	-	-	-	-	-	-	-
SCHMDP-SG	SCHMDP	SG	P	-	-	-	-	-	-	-	-	-
SCHMDP-SNP	SCHMDP	SNP	PTD	107	50.94	26.42	28.28	-	-	-	0.97	-
SCHMDP-SO	SCHMDP	SO	LABOR	-	-	-	-	-	-	-	-	-
SCHMDP-SITUS	SCHMDP	SITUS	PTD	-	-	-	-	-	-	-	-	-
	Total-SO			-	-	-	-	-	-	-	-	-
	Total-SCHMDP			87	43	25	21	(0)	-	(1)	(0)	(1)
	SCHMDP-SO			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	SCHMDP FACTOR			100.00%	49.3532%	28.5855%	24.4573%	-0.1274%	0.0000%	-1.1306%	-0.3340%	-0.8039%
SCHMDT-BADDEBT	SCHMDT	BADDEBT	CUST	-	-	-	-	-	-	-	-	-
SCHMDT-CN	SCHMDT	CN	CUST	-	-	-	-	-	-	-	-	-
SCHMDT-GPS	SCHMDT	GPS	GP	-	-	-	-	-	-	-	-	-
SCHMDT-GPS	SCHMDT	GPS	P	-	-	-	-	-	-	-	-	-
SCHMDT-GPS	SCHMDT	GPS	PTD	68,083	32,530	16,871	18,061	-	-	-	621	-
SCHMDT-SG	SCHMDT	SG	P	146,912	146,912	-	-	-	-	-	-	-
SCHMDT-SG	SCHMDT	SG	T	(1,520)	-	(1,520)	-	-	-	-	-	-
SCHMDT-SE	SCHMDT	SE	P	(1,172)	(1,172)	-	-	-	-	-	-	-
SCHMDT-SNPD	SCHMDT	SNPD	DPW	(22)	-	-	(21)	-	-	-	(1)	-
SCHMDT-SNPD	SCHMDT	SNPD	P	1,548	1,548	-	-	-	-	-	-	-
SCHMDT-SNP	SCHMDT	SNP	PTD	74,705	35,694	18,512	19,818	-	-	-	681	-
SCHMDT-SO	SCHMDT	SO	ESD	1,876	563	188	1,125	-	-	-	-	-
SCHMDT-SO	SCHMDT	SO	GP	5,977	2,786	1,498	1,605	-	-	16	62	10
SCHMDT-SO	SCHMDT	SO	LABOR	16,000	6,510	1,220	5,738	92	-	815	1,045	580
SCHMDT-SO	SCHMDT	SO	PTD	(788)	(377)	(195)	(209)	-	-	-	(7)	-
SCHMDT-OTHER	SCHMDT	OTHER	CUST	7	-	-	-	-	-	7	-	-
SCHMDT-OTHER	SCHMDT	OTHER	DDS2	(124)	(124)	(7)	(39)	(0)	-	49	(1)	(1)
SCHMDT-OTHER	SCHMDT	OTHER	DMSC	313	-	-	313	-	-	-	-	-
SCHMDT-OTHER	SCHMDT	OTHER	DPW	-	-	-	-	-	-	-	-	-
SCHMDT-OTHER	SCHMDT	OTHER	LABOR	-	-	-	-	-	-	-	-	-
SCHMDT-OTHER	SCHMDT	OTHER	P	48,484	48,484	-	-	-	-	-	-	-
SCHMDT-OTHER	SCHMDT	OTHER	PT	-	-	-	-	-	-	-	-	-
SCHMDT-OTHER	SCHMDT	OTHER	PTD	429	205	106	114	-	-	-	4	-
SCHMDT-OTHER	SCHMDT	OTHER	GP	24,141	11,252	6,052	6,482	-	-	64	252	41
SCHMDT-TAXDEPR	SCHMDT	TAXDEPR	TAXDEPR	590,718	330,675	107,672	142,513	139	-	3,780	3,332	2,608
SCHMDT-SITUS	SCHMDT	SITUS	DMSC	88	-	-	88	-	-	-	-	-
SCHMDT-SITUS	SCHMDT	SITUS	DDS2	(497)	(497)	(29)	(158)	(0)	-	195	(5)	(3)
SCHMDT-SITUS	SCHMDT	SITUS	GP	(187)	(87)	(47)	(50)	-	-	(0)	(2)	(0)
SCHMDT-SITUS	SCHMDT	SITUS	LABOR	549	223	42	197	3	-	28	36	20
SCHMDT-SITUS	SCHMDT	SITUS	P	(926)	(926)	-	-	-	-	-	-	-
SCHMDT-SITUS	SCHMDT	SITUS	PTD	0	0	0	0	-	-	-	0	-
	Total-GPS			68,083	32,530	16,871	18,061	-	-	-	621	-
	Total-CN			-	-	-	-	-	-	-	-	-
	Total-SG			145,392	146,912	(1,520)	-	-	-	-	-	-
	Total-SE			(1,172)	(1,172)	-	-	-	-	-	-	-
	Total-SNP			74,705	35,694	18,512	19,818	-	-	-	681	-
	Total SO			23,065	9,482	2,710	8,259	92	-	831	1,100	590
	Total OTHER			73,251	59,817	6,151	6,870	(0)	-	119	254	40
	Total TAXDEPR			590,718	330,675	107,672	142,513	139	-	3,780	3,332	2,608
	Total-SITUS			(972)	(1,286)	(34)	77	3	-	222	29	17
	Total SCHMDT			974,596	614,201	150,362	195,577	234	-	4,952	6,017	3,254
	SCHMDT-GPS			100.00%	47.7801%	24.7796%	26.5283%	0.0000%	0.0000%	0.0000%	0.9121%	0.0000%
	SCHMDT-CN			0.00%								

PacifiCorp
12 Months Ended June 2019
Schedule M

	Primary Account	PITA Factor	Function	Amount	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
	SCHMDT-SG			100.00%	101.0454%	-1.0454%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	SCHMDT-SE			100.00%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	SCHMDT-SNP			100.00%	47.7801%	24.7796%	26.5283%	0.0000%	0.0000%	0.0000%	0.9121%	0.0000%
	SCHMDT-SO			100.00%	41.1112%	11.7514%	35.8093%	0.3984%	0.0000%	3.6037%	4.7684%	2.5576%
	SCHMDT-OTHER			100.00%	81.6605%	8.3973%	9.3781%	-0.0002%	0.0000%	0.1624%	0.3473%	0.0546%
	SCHMDT-TAXDEPR			100.00%	55.9785%	18.2272%	24.1253%	0.0236%	0.0000%	0.6398%	0.5641%	0.4414%
	SCHMDT-SITUS			100.00%	132.2711%	3.4730%	-7.9326%	-0.2779%	0.0000%	-22.8529%	-2.9593%	-1.7213%
	SCHMDT FACTOR			100.00%	63.0211%	15.4281%	20.0675%	0.0240%	0.0000%	0.5081%	0.6174%	0.3339%
SCHMDF-DGP	SCHMDF	DGP	P	-	-	-	-	-	-	-	-	-
	Total-SCHMDF			-	-	-	-	-	-	-	-	-
	SCHMDF FACTOR			0.00%								
	Total-SCHMD			974,683	614,244	150,387	195,598	234	-	4,951	6,017	3,254
	SCHMD FACTOR			100.00%	63.0199%	15.4293%	20.0679%	0.0240%	0.0000%	0.5080%	0.6173%	0.3338%

Net SCHM

Function	Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service
DMSC	100.00%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DPW	100.00%	0.0000%	0.0000%	96.6760%	0.0000%	0.0000%	0.0000%	3.3240%	0.0000%
DDS2	100.00%	99.9424%	5.7852%	31.7729%	0.0904%	0.0000%	-39.1897%	1.0281%	0.5706%
CUST	100.00%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
ESD	100.00%	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
GP	100.00%	46.6071%	25.0685%	26.8495%	0.0000%	0.0000%	0.2636%	1.0427%	0.1686%
LABOR	100.00%	40.6891%	7.6237%	35.8635%	0.5743%	0.0000%	5.0964%	6.5291%	3.6238%
P	100.00%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PT	100.00%	65.8494%	34.1506%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PTD	100.00%	47.7801%	24.7796%	26.5283%	0.0000%	0.0000%	0.0000%	0.9121%	0.0000%
T	100.00%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
TAXDEPR	100.00%	55.9785%	18.2272%	24.1253%	0.0236%	0.0000%	0.6398%	0.5641%	0.4414%
TD	100.00%	0.0000%	47.4523%	50.8010%	0.0000%	0.0000%	0.0000%	1.7467%	0.0000%

PacifiCorp
12 Months Ended June 2019
Account 456

Main Account	Factor	Function	Amount	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM
456	SO	DMSC	(4,092)	0	0	-4,092	0	0	0	0	0	0
457	OTHER	P	(10,294)	-10,294	0	0	0	0	0	0	0	0
458	OTHER	T	-	0	0	0	0	0	0	0	0	0
456	SE	T	(17,029)	0	-17,029	0	0	0	0	0	0	0
456	SE	P	-	0	0	0	0	0	0	0	0	0
456	SG	P	(21,317)	-21,317	0	0	0	0	0	0	0	0
456	SG	T	(98,659)	0	-98,659	0	0	0	0	0	0	0
456	SG	DMSC	(2)	0	0	-2	0	0	0	0	0	0
457	SITUS	T	4,012	0	4,012	0	0	0	0	0	0	0
456	SITUS	DMSC	4,488	0	0	4,488	0	0	0	0	0	0
456	SITUS	P	(158)	-158	0	0	0	0	0	0	0	0
Total Situs Revenues			8,342	-158	4,012	4,488	0	0	0	0	0	0
Total CN Revenues			0	0	0	0	0	0	0	0	0	0
Total SE Revenues			-17,029	0	-17,029	0	0	0	0	0	0	0
Total SG Revenues			-119,978	-21,317	-98,659	-2	0	0	0	0	0	0
Total SO Revenues			-4,092	0	0	-4,092	0	0	0	0	0	0
Total Operation			-143,051	-31,769	-111,676	394	0	0	0	0	0	0
OTHSITUS			100.0000%	-1.8974%	48.0979%	53.7995%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
CN Factor			0.0000%									
OTHSE			100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
OTHSG			100.0000%	17.7673%	82.2308%	0.0019%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
OTHSO			100.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Total Operation Factor			100.0000%	22.2083%	78.0669%	-0.2752%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

	Total	Production	Transmission	Distribution	Distribution-LGT	Ancillary	C_Billing	C_Metering	C_Service	DSM
P	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
T	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TD	100.00%	0.00%	47.45%	50.80%	0.00%	0.00%	0.00%	1.75%	0.00%	0.00%
CUST	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
DPW	100.00%	0.00%	0.00%	96.68%	0.00%	0.00%	0.00%	3.32%	0.00%	0.00%
PTD	100.00%	47.78%	24.78%	26.53%	0.00%	0.00%	0.00%	0.91%	0.00%	0.00%
DMSC	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Docket No. UE 374
Exhibit PAC/1405
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Ancillary Services Revenue Requirement

February 2020

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Ancillary Services Revenue
12 Months Ended December 31, 2021 Forecast

Oregon Annual Ancillary Service Revenue $24,876,786

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[1]

Line	Description	Calculation	Value
1	Sum of 12 Oregon Monthly Peaks (MW)		27,103
2	Total Oregon Retail Load (MWh)		15,219,850
3			
4	Schedule 3 Load Rate ($/MW-month)		$177
5	Schedule 3 Revenue	1*4	$4,797,165
6			
7	Schedule 5 Rate ($/MWh)		$0.151
8	Schedule 5 Revenue	2*7	$2,298,197
9			
10	Schedule 6 Rate ($/MWh)		$0.151
11	Schedule 6 Revenue	2*10	$2,298,197
12			
13			
14	Total Oregon Load Revenue	5+8+11	$9,393,559

Generation

Line	Description	Calculation	Value
1	Sum of 12 Total System VER Generator Nameplate Capacities (MW)[2]		68,370
2	Sum of 12 Total System Non-VER Generator Nameplate Capacities (MW)		12,534
3	Total System Generation MWh at input		66,502,586
4			
5	Schedule 3A VER Rate ($/MW-month)		$549
6	Schedule 3A VER Revenue	1*5	$37,535,255
7			
8	Schedule 3A Non-VER Rate ($/MW-month)		$150
9	Schedule 3A Non-VER Revenue	2*8	$1,880,042
10			
11	Schedule 5 Rate ($/MWh)		$0.151
12	Schedule 5 Revenue	3*11	$10,041,891
13			
14	Schedule 6 Rate ($/MWh)		$0.151
15	Schedule 6 Revenue	3*14	$10,041,891
16			
17			
18	Total Generation Revenue	6+9+12+15	$59,499,078
19			
20	Oregon JAM SG Factor		26%
21	Oregon-allocated Total Generation Revenue	18*20	$15,483,227

[1]Load is Oregon's Contributions to Monthly Firm System Retail Load at input
[2]All VER Generation is assumed to be Uncommitted (see OATT Schedule 3A requirements for Committed and Uncommitted)

Docket No. UE 374
Exhibit PAC/1406
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Oregon Marginal Cost of Service Study Summary

February 2020

PACIFICORP
STATE OF OREGON
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
12 Months Ended December 31, 2021 Forecast
(Dollars in 000s)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41	Lighting
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn		Schs 15, 51,
Line	Class / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	53, 54 (sec)
1	Demand Related Marginal Cost																			
2	Generation	$266,496	$124,692	$11,107	$10,934	$18	$8,447	$13,198	$18,553	$511	$3,849	$19,633	$1,927	$9,424	$9,447	$901	$16,126	$13,976	$3,752	$0
3	Transmission	$8,194	$3,834	$342	$336	$1	$260	$406	$570	$16	$118	$604	$59	$290	$290	$28	$496	$430	$115	$0
4	Distribution																			
5	Poles	$41,148	$19,712	$2,593	$2,693	$2	$1,202	$1,952	$2,765	$73	$461	$2,242	$216	$2,658	$2,641	$9	$119	$0	$1,744	$67
6	Conductor	$70,065	$35,232	$3,956	$4,108	$3	$2,153	$3,498	$4,955	$131	$902	$4,384	$422	$3,790	$3,765	$19	$256	$0	$2,389	$102
7	Substations	$41,626	$21,293	$1,721	$1,787	$2	$1,332	$2,163	$3,065	$81	$644	$3,130	$302	$1,458	$1,448	$137	$2,444	$0	$622	$0
8	Transformers	$9,080	$6,001	$458	$294	$0	$237	$427	$535	$0	$79	$505	$0	$208	$0	$25	$0	$0	$281	$29
9	Total Demand	$436,610	$210,765	$20,176	$20,152	$25	$13,630	$21,643	$30,445	$812	$6,053	$30,497	$2,926	$17,829	$17,591	$1,118	$19,441	$14,405	$8,903	$198
10																				
11																				
12	Energy Related Marginal Cost																			
13	Generation	$479,116	$199,213	$20,999	$19,703	$73	$15,591	$24,217	$32,816	$910	$7,160	$38,436	$3,427	$18,040	$18,490	$1,992	$35,638	$33,634	$7,994	$782
14	Transmission	$190	$79	$8	$8	$0	$6	$10	$13	$0	$3	$15	$1	$7	$7	$1	$14	$13	$3	$0
15	Total Energy	$479,306	$199,292	$21,008	$19,711	$73	$15,597	$24,227	$32,829	$911	$7,163	$38,451	$3,429	$18,047	$18,497	$1,992	$35,652	$33,648	$7,997	$782
16																				
17	Customer Related Marginal Cost																			
18	Poles	$54,210	$40,278	$9,375	$1,663	$12	$355	$280	$161	$6	$14	$35	$3	$16	$10	$0	$0	$0	$2,003	$0
19	Conductor	$28,994	$21,544	$5,014	$890	$6	$190	$150	$86	$3	$7	$19	$2	$9	$5	$0	$0	$0	$1,071	$0
20	Transformers	$77,051	$47,015	$11,034	$2,953	$0	$3,429	$3,025	$1,894	$0	$246	$630	$0	$104	$0	$2	$0	$0	$6,719	$0
21	Lighting	$5,235	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,235
22	Service Drops	$53,173	$40,056	$7,026	$2,555	$0	$978	$798	$898	$0	$98	$485	$0	$272	$0	$6	$0	$0	$0	$0
23	Meters	$16,840	$12,753	$1,838	$396	$141	$163	$137	$422	$114	$46	$119	$87	$24	$94	$0	$45	$161	$296	$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	$17,549	$14,567	$1,958	$347	$3	$143	$113	$65	$2	$7	$18	$2	$14	$8	$0	$4	$1	$106	$191
26	Uncollectables	$5,313	$4,413	$162	$29	$0	$122	$96	$55	$2	$39	$99	$9	$94	$58	$2	$28	$7	$98	$0
27	Customer Service / Other	$5,156	$4,275	$562	$100	$1	$42	$33	$19	$1	$3	$9	$1	$5	$3	$0	$1	$0	$41	$59
28	Total Customer (Commitment & Billing)	$263,521	$184,902	$36,969	$8,932	$162	$5,423	$4,631	$3,601	$127	$460	$1,413	$104	$538	$179	$11	$79	$169	$10,335	$5,488
29																				
30																				
31	Total Revenue @ Full MC																			
32	Generation	$745,612	$323,906	$32,106	$30,638	$91	$24,038	$37,415	$51,369	$1,422	$11,009	$58,069	$5,355	$27,464	$27,936	$2,893	$51,764	$47,610	$11,746	$782
33	Transmission	$8,384	$3,913	$350	$344	$1	$266	$415	$583	$16	$121	$619	$61	$297	$298	$29	$510	$443	$119	$0
34	Distribution	$375,348	$231,131	$41,178	$16,942	$26	$9,876	$12,291	$14,360	$294	$2,450	$11,428	$945	$8,516	$7,869	$196	$2,819	$0	$14,829	$198
35	Distribution-Lighting	$5,235	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,235
36	Customer - Billing	$17,549	$14,567	$1,958	$347	$3	$143	$113	$65	$2	$7	$18	$2	$14	$8	$0	$4	$1	$106	$191
37	Customer - Metering	$16,840	$12,753	$1,838	$396	$141	$163	$137	$422	$114	$46	$119	$87	$24	$94	$0	$45	$161	$296	$3
38	Customer - Other	$5,156	$4,275	$562	$100	$1	$42	$33	$19	$1	$3	$9	$1	$5	$3	$0	$1	$0	$41	$59
39	Revenue (less Uncollectables)	$1,174,124	$590,546	$77,991	$48,767	$261	$34,529	$50,405	$66,819	$1,848	$13,637	$70,261	$6,450	$36,319	$36,208	$3,119	$55,144	$48,215	$27,137	$6,468
40																				
41	Customer - Uncollectables	$5,313	$4,413	$162	$29	$0	$122	$96	$55	$2	$39	$99	$9	$94	$58	$2	$28	$7	$98	$0
42	Total Revenue	$1,179,437	$594,959	$78,153	$48,795	$261	$34,650	$50,501	$66,874	$1,850	$13,676	$70,360	$6,460	$36,413	$36,267	$3,121	$55,172	$48,222	$27,235	$6,468

Docket No. UE 374
Exhibit PAC/1407
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Unbundled Revenue Requirement Allocation

February 2020

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2021 Unbundled Revenue Requirement Allocation by Load Class

Line	Description	Total	(A) Residential	(B) General Service Sch 23	(C) General Service Sch 23	(D) General Service Sch 28	(E) General Service Sch 28	(F) General Service Sch 30	(G) General Service Sch 30	(H) Large Power Service Sch 48	(I) Large Power Service Sch 48	(J) Large Power Service Sch 48	(K) Irrigation Sch 41	(L) Lighting Schs 15, 51, 53, and 54	Lighting Detail Schs 15 & 51	Lighting Detail Sch 53	Lighting Detail Sch 54
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)		(sec)	(sec)	(sec)
1	Total Operating Revenues	$1,297,086	$628,518	$125,863	$217	$184,421	$2,261	$102,874	$7,939	$43,528	$108,818	$61,458	$25,947	$5,242	$4,366	$754	$121
2	MWh	13,374,494	5,521,127	1,128,061	2,086	2,012,760	25,965	1,263,680	97,746	555,158	1,543,656	981,023	221,554	21,677	8,174	12,046	1,457
3																	
4	Functionalized 20 Year Full Marginal Costs - Class $																
5	Generation	$745,612	$323,906	$62,744	$91	$112,823	$1,422	$69,078	$5,355	$30,357	$79,700	$47,610	$11,746	$782	$295	$435	$53
6	Transmission	$8,384	$3,913	$694	$1	$1,265	$16	$740	$61	$325	$808	$443	$119	$0	$0	$0	$0
7	Distribution	$375,348	$231,131	$58,120	$26	$36,527	$294	$13,878	$945	$8,712	$10,688	$0	$14,829	$198	$169	$23	$5
8	Distribution-Lighting	$5,235	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,235	$5,235	$0	$0
9	Customer - Billing	$17,549	$14,567	$2,305	$3	$321	$2	$25	$2	$14	$12	$1	$106	$191	$181	$8	$3
10	Customer - Metering	$16,840	$12,753	$2,234	$141	$723	$114	$165	$87	$25	$139	$161	$296	$3	$0	$0	$3
11	Customer - Other	$5,156	$4,275	$661	$1	$95	$1	$12	$1	$5	$5	$0	$41	$59	$56	$2	$1
12	Total	$1,174,124	$590,546	$126,757	$261	$151,753	$1,848	$83,898	$6,450	$39,438	$91,352	$48,215	$27,137	$6,468	$5,936	$468	$64
13																	
14	Functional Revenue Requirement Allocation Factors																
15	Functionalized 20 Year Full Marginal Costs - Class % of Total																
16	Generation	100.00%	43.44%	8.42%	0.01%	15.13%	0.19%	9.26%	0.72%	4.07%	10.69%	6.39%	1.58%	0.10%	0.04%	0.06%	0.01%
17	Transmission	100.00%	46.67%	8.28%	0.01%	15.09%	0.19%	8.83%	0.72%	3.88%	9.63%	5.28%	1.41%	0.00%	0.00%	0.00%	0.00%
18	Distribution	100.00%	61.58%	15.48%	0.01%	9.73%	0.08%	3.70%	0.25%	2.32%	2.85%	0.00%	3.95%	0.05%	0.05%	0.01%	0.00%
19	Distribution-Lighting	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%	0.00%
20	Ancillary Service	100.00%	43.44%	8.42%	0.01%	15.13%	0.19%	9.26%	0.72%	4.07%	10.69%	6.39%	1.58%	0.10%	0.04%	0.06%	0.01%
21	Customer - Billing	100.00%	83.01%	13.14%	0.01%	1.83%	0.01%	0.14%	0.01%	0.08%	0.07%	0.01%	0.60%	1.09%	1.03%	0.04%	0.02%
22	Customer - Metering	100.00%	75.73%	13.26%	0.83%	4.29%	0.68%	0.98%	0.52%	0.15%	0.83%	0.95%	1.76%	0.02%	0.00%	0.00%	0.02%
23	Customer - Other	100.00%	82.92%	12.83%	0.01%	1.84%	0.01%	0.24%	0.02%	0.10%	0.09%	0.01%	0.79%	1.14%	1.08%	0.05%	0.02%
24	Embedded DSM - (MWh)	100.00%	41.28%	8.43%	0.02%	15.05%	0.19%	9.45%	0.73%	4.15%	11.54%	7.34%	1.66%	0.16%	0.06%	0.09%	0.01%
25	Regulatory & Franchise - (Total Operating Revenues)	100.00%	48.46%	9.70%	0.02%	14.22%	0.17%	7.93%	0.61%	3.36%	8.39%	4.74%	2.00%	0.40%	0.34%	0.06%	0.01%
26																	
27																	
28	Functionalized Class Revenue Requirement - (Target)																
29	Generation	$723,590	$314,339	$60,890	$88	$109,490	$1,380	$67,038	$5,197	$29,460	$77,346	$46,204	$11,399	$759	$286	$422	$51
30	Transmission	$215,546	$100,599	$17,838	$15	$32,517	$413	$19,027	$1,558	$8,367	$20,767	$11,390	$3,047	$8	$3	$4	$1
31	Distribution	276,270	$170,122	$42,778	$19	$26,885	$216	$10,215	$695	$6,412	$7,867	$0	$10,915	$146	$125	$17	$4
32	Distribution-Lighting	$3,245	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,245	$3,245	$0	$0
33	Distribution Total	279,515	$170,122	$42,778	$19	$26,885	$216	$10,215	$695	$6,412	$7,867	$0	$10,915	$3,391	$3,370	$17	$4
34	Ancillary Services	$24,648	$10,708	$2,074	$3	$3,730	$47	$2,284	$177	$1,004	$2,635	$1,574	$388	$26	$10	$14	$2
35	Customer - Billing	$10,773	$8,942	$1,415	$2	$197	$1	$15	$1	$8	$8	$1	$65	$117	$111	$5	$2
36	Customer - Metering	$26,349	$19,955	$3,495	$220	$1,131	$178	$258	$137	$39	$218	$251	$464	$4	$0	$0	$4
37	Customer - Other	$11,668	$9,675	$1,497	$2	$215	$1	$28	$2	$12	$10	$1	$92	$133	$126	$5	$2
38	Embedded DSM - (MWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
39	Franchise Fees	$33,284	$16,128	$3,230	$6	$4,732	$58	$2,640	$204	$1,117	$2,792	$1,577	$666	$135	$112	$19	$3
40	Total	$1,325,372	$650,467	$133,218	$353	$178,897	$2,295	$101,503	$7,971	$46,418	$111,642	$60,998	$27,036	$4,573	$4,018	$487	$68
41																	
42	Ratio of Operating Revn to Revenue Requirement-(Target)	97.87%	96.63%	94.48%	61.52%	103.09%	98.50%	101.35%	99.59%	93.77%	97.47%	100.75%	95.97%	114.62%	108.68%	154.91%	177.10%
43	(Line 1 / Line 40)																
44																	
45	Increase or (Decrease)	$28,286	$21,949	$7,354	$136	($5,525)	$34	($1,370)	$32	$2,891	$2,824	($460)	$1,089	($669)	($349)	($267)	($53)
46	(Line 40 - Line 1)																
47																	
48																	
49	Percent Increase (Decrease)	2.18%	3.49%	5.84%	62.56%	-3.00%	1.52%	-1.33%	0.41%	6.64%	2.60%	-0.75%	4.20%	-12.76%	-7.98%	-35.45%	-43.53%
50	(Line 45 / Line 1)																

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2021 Functionalized Revenue - Earned
($ 000)

		A	B	C	D	E	F	G	I	J	K
Line No.	Description	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C Billing	C Metering	C Other	Franchise Fees	Total
1	Earned Functional Revenue Requirement	$719,612	$208,935	$270,870	$3,174	$24,877	$10,792	$25,971	$11,745	$32,910	$1,308,885
2											
3	Percent of Total	54.98%	15.96%	20.69%	0.24%	1.90%	0.82%	1.98%	0.90%	2.51%	100.00%
4											
5	Revenue From Classes Included in MC Study	$713,125	$207,051	$268,428	$3,145	$24,653	$10,694	$25,737	$11,639	$32,613	$1,297,086
6											
7	Other Revenues										
8	Schedule 4 - Employee Discount										($392)
9	Partial Requirements - Sch. 47 pri										$2,366
10	Partial Requirements - Sch. 47 trn										$2,883
11	Sch 848										$2,222
12	Oregon Direct Access Opt Out Amortization										$1,727
13	AGA										$2,993
14	Total Oregon Situs Revenue										$1,308,885

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2021 Functionalized Revenue - Target
($ 000)

		A	B	C	D	E	F	G	I	J	K	
Line No.	Description	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C Billing	C Metering	C Other	Franchise Fees	Total	
1	Target Functional Revenue Requirement	$730,302	$217,545	$278,833	$3,275	$24,877	$10,873	$26,593	$11,776	$33,593	$1,337,667	
2												
3	Percent of Total	54.60%	16.26%	20.84%	0.24%	1.86%	0.81%	1.99%	0.88%	2.51%	100.00%	
4												Increase
5	Revenue From Classes Included in MC Study	$723,590	$215,546	$276,270	$3,245	$24,648	$10,773	$26,349	$11,668	$33,284	$1,325,372	$28,286
6												
7	Other Revenues											$28,783
8	Schedule 4 - Employee Discount										($405)	($13)
9	Partial Requirements - Sch. 47 pri										$2,606	$240
10	Partial Requirements - Sch. 47 trn										$2,984	$101
11	Sch 848										$2,391	$169
12	Oregon Direct Access Opt Out Amortization										$1,727	$0
13	AGA										$2,993	$0
14	Total Oregon Situs Revenue										$1,337,667	

PACIFICORP
State of Oregon
December 31, 2021 Unbundled Revenue Requirement Allocation by Load Class
FERC Transmission Revenue ($ 000)

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
		Total	Residential	General Service Schedule 23		General Service Schedule 28		General Service Schedule 30		Large Power Service Schedule 48			Schedule 41	Lighting
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	Irrigation	(sec)
1	Total Transmission Revenue Requirement	$215,546	$100,599	$17,838	$15	$32,517	$413	$19,027	$1,558	$8,367	$20,767	$11,390	$3,047	$8
2														
3	FERC Transmission													
4	Peak MW @ Input	2,264	1,059	187	0	341	4	199	16	88	217	119	32	0
5	% of Total	100.00%	46.79%	8.27%	0.01%	15.08%	0.19%	8.81%	0.72%	3.87%	9.60%	5.24%	1.41%	0.00%
6	FERC Transmission Revenues ($ 000)	$73,934	$34,593	$6,115	$5	$11,152	$142	$6,515	$535	$2,865	$7,095	$3,877	$1,041	$0
7														
8	Other Transmission Revenue Requirement	$141,612	$66,005	$11,723	$10	$21,364	$272	$12,512	$1,024	$5,502	$13,672	$7,513	$2,006	$8

	OR CP (MW)
Jan	2,638
Feb	2,448
Mar	2,364
Apr	2,225
May	1,914
Jun	2,051
Jul	2,376
Aug	2,449
Sep	2,138
Oct	1,890
Nov	2,206
Dec	2,402
Annual Average	2,259

Network service rate ($/MW-year)[1]	$32,735
FERC Transmission Revenues	$73,933,702

[1]From 2019 Transmission Formula Rate Annual Update p.14

Docket No. UE 374
Exhibit PAC/1408
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Oregon Marginal Cost of Service Study

February 2020

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, 10 and 20 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 10- and 20-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 10 or 20 years of generation costs, transmission and distribution costs.

One-, 10- and 20-year marginal costs are summarized by customer class and load size group and shown in mills/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 2021 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 2021.

One, 10- and 20-year marginal costs in mills/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 20-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 2021 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 administration and general (A&G) expense loading factor and a transmission operation and maintenance (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 to 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/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 dollars/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 10 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.

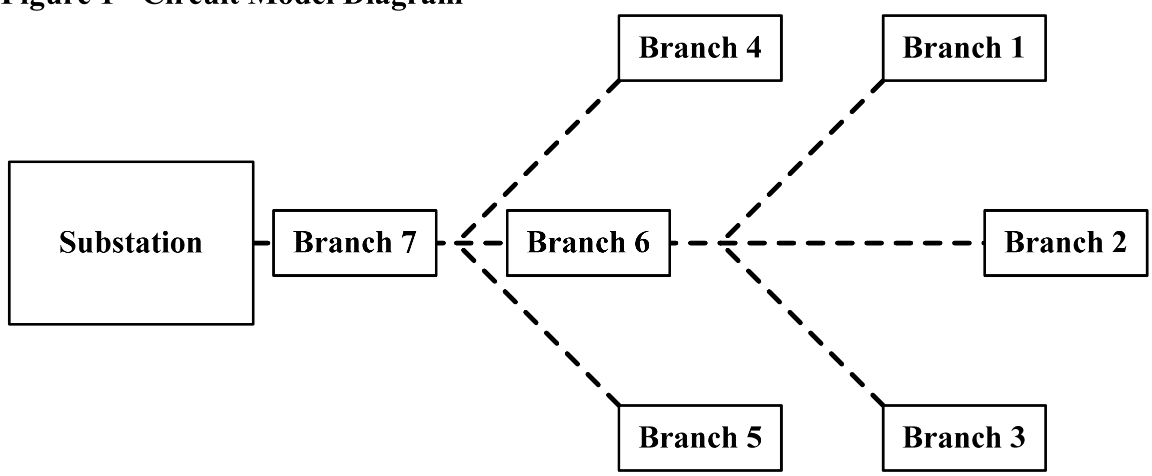
Weighted average installed service drop cost calculations are located on Sheets 'Services 1' through 'Services 3' and the weighted average installed meter cost calculations are included on Sheets 'Meters 1' through 'Meters 5'. The customer accounting and informational expense calculation is on page "Summary 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	55,605	12,356,706	2,340	23.76	0.907
Idaho	97,159	22,745,816	4,308	22.55	0.861
Oregon	372,724	75,328,924	14,267	26.13	0.997
Utah	337,400	57,744,612	10,936	30.85	1.177
Washington	99,821	18,927,800	3,585	27.85	1.063
Wyoming	156,902	38,489,046	7,290	21.52	0.821
Total	1,119,611	225,592,904	42,726	26.20	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	$23,990	0.997	$23,918	$12,792	$36,710
3 Phase - 1/0 ACSR	$43,964	0.997	$43,832	$28,864	$72,696
3 Phase - 447 AAC & 4\0 AAC	$49,159	0.997	$49,012	$62,211	$111,223
3 Phase -795 AAC & 477 AAC	$51,257	0.997	$51,103	$110,152	$161,255

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. 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)	0.33%	0.33%	0.33%	1.79%	1.79%	1.79%	93.66%	100.00%
GS - Schedule 23 - 0-15 kW (sec)	0.76%	0.76%	0.76%	2.59%	2.59%	2.59%	89.97%	100.00%
GS - Schedule 23 - 15+ kW (sec)	0.76%	0.76%	0.76%	2.59%	2.59%	2.59%	89.97%	100.00%
GS - Schedule 23 - Primary (pri)	0.76%	0.76%	0.76%	2.59%	2.59%	2.59%	89.97%	100.00%
GS - Schedule 28 - 0-50 kW (sec)	0.38%	0.38%	0.38%	1.40%	1.40%	1.40%	94.65%	100.00%
GS - Schedule 28 - 51-100 kW (sec)	0.38%	0.38%	0.38%	1.40%	1.40%	1.40%	94.65%	100.00%
GS - Schedule 28 - 100 + kW (sec)	0.38%	0.38%	0.38%	1.40%	1.40%	1.40%	94.65%	100.00%
GS - Schedule 28 - Primary (pri)	0.38%	0.38%	0.38%	1.40%	1.40%	1.40%	94.65%	100.00%
GS - Schedule 30 - 0-300 kW (sec)	0.32%	0.32%	0.32%	0.78%	0.78%	0.78%	96.69%	100.00%
GS - Schedule 30 - 300+ kW (sec)	0.32%	0.32%	0.32%	0.78%	0.78%	0.78%	96.69%	100.00%
GS - Schedule 30 - Primary (pri)	0.32%	0.32%	0.32%	0.78%	0.78%	0.78%	96.69%	100.00%
Irrigation - Sch 41	0.98%	0.98%	0.98%	7.86%	7.86%	7.86%	73.47%	100.00%
LPS - Schedule 48T - 1 - 4 MW (sec)	1.31%	1.31%	1.31%	1.48%	1.48%	1.48%	91.63%	100.00%
LPS - Schedule 48T - 1 - 4 MW (pri)	1.31%	1.31%	1.31%	1.48%	1.48%	1.48%	91.63%	100.00%
LPS - Schedule 48T - > 4 MW (sec)	Large Customers are on dedicated circuits and are not included here							
LPS - Schedule 48T - > 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

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1		Hypothetical Circuit Branch							
2	Class	1	2	3	4	5	6	7	Total
3	Residential	3.11	3.11	3.11	16.98	16.98	16.98	890.73	951.01
4	GS 0-15 kW (sec) (23)	1.00	1.00	1.00	3.43	3.43	3.43	119.20	132.49
5	GS >15 kW (sec) (23)	0.18	0.18	0.18	0.61	0.61	0.61	21.15	23.50
6	GS (pri) (23)	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.17
7	GS < 50 kW (sec) (28)	0.03	0.03	0.03	0.12	0.12	0.12	8.12	8.58
8	GS 51-100 kW (sec) (28)	0.03	0.03	0.03	0.09	0.09	0.09	6.39	6.76
9	GS > 100 kW (sec) (28)	0.01	0.01	0.01	0.05	0.05	0.05	3.68	3.89
10	GS (pri) (28)	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.13
11	GS 0-300 kW (sec) (30)	0.00	0.00	0.00	0.00	0.00	0.00	0.41	0.42
12	GS >300 kW (sec) (30)	0.00	0.00	0.00	0.01	0.01	0.01	1.05	1.09
13	GS (pri) (30)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.10
14	Irrigation	0.12	0.12	0.12	0.98	0.98	0.98	9.17	12.48
15	Large GS 1 - 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.18
16	Large GS 1 - 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.11
17	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
18	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
19	Total	4.50	4.50	4.50	22.29	22.29	22.29	1,060.55	1,140.92

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

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1		Hypothetical Circuit Branch							
2	Class	1	2	3	4	5	6	7	Total
3	Residential	6.91	6.91	6.91	37.74	37.74	37.74	1,979.40	2,113.35
4	GS 0-15 kW (sec) (23)	1.29	1.29	1.29	4.42	4.42	4.42	153.65	170.78
5	GS >15 kW (sec) (23)	1.34	1.34	1.34	4.59	4.59	4.59	159.55	177.34
6	GS (pri) (23)	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.16
7	GS < 50 kW (sec) (28)	0.51	0.51	0.51	1.85	1.85	1.85	125.11	132.18
8	GS 51-100 kW (sec) (28)	0.82	0.82	0.82	3.01	3.01	3.01	203.21	214.70
9	GS > 100 kW (sec) (28)	1.16	1.16	1.16	4.26	4.26	4.26	287.90	304.17
10	GS (pri) (28)	0.03	0.03	0.03	0.12	0.12	0.12	7.83	8.27
11	GS 0-300 kW (sec) (30)	0.21	0.21	0.21	0.50	0.50	0.50	61.78	63.89
12	GS >300 kW (sec) (30)	1.00	1.00	1.00	2.43	2.43	2.43	300.33	310.61
13	GS (pri) (30)	0.10	0.10	0.10	0.24	0.24	0.24	29.78	30.80
14	Irrigation	0.61	0.61	0.61	4.85	4.85	4.85	45.37	61.75
15	Large GS 1 - 4 MW (sec)	1.90	1.90	1.90	2.14	2.14	2.14	132.55	144.67
16	Large GS 1 - 4 MW (pri)	1.94	1.94	1.94	2.19	2.19	2.19	135.50	147.88
17	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
18	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
19	Total	17.83	17.83	17.83	68.33	68.33	68.33	3,622.07	3,880.54

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 percent 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

	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	$23,990	0.997	$23,918	$12,792	$36,710
3 Phase - 1/0 ACSR	$43,964	0.997	$43,832	$28,864	$72,696
3 Phase - 447 AAC & 4\0 AAC	$49,159	0.997	$49,012	$62,211	$111,223
3 Phase -795 AAC & 477 AAC	$51,257	0.997	$51,103	$110,152	$161,255

	Costs for Branches 1,2,3,4,5		
	1 Phase - 1/0 ACSR	3 Phase - 1/0 ACSR	Total
Poles	$44,168	$150,321	$194,489
Conductors	$23,622	$98,988	$122,611
Total	$67,790	$249,309	$317,099

	Costs for Branch 6	Cost for Branch 7
	3 Phase - 447 AAC & 4\0 AAC	3 Phase -795 AAC & 477 AAC
Poles	$258,590	$269,626
Conductors	$328,232	$581,174
Total	$586,822	$850,801

Miles per Branch	5.28
Single Phase Miles Per Branch	1.85
Three Phase Miles Per Branch	3.43

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

		(A)	(B)	(C)	(D)	(E)	(F)
		Total Cost		Commitment Cost		Demand Cost	
	Conductors Type	Poles	Conductor	Poles	Conductor	Poles	Conductor
Branch 1							
	1 Phase - 1/0 ACSR	$ 44,168	$ 23,622	$ 44,168	$ 23,622	NA	NA
	3 Phase - 1/0 ACSR	$ 150,321	$ 98,988	$ 82,026	$ 43,870	$ 68,295	$ 55,118
	Total segment	$ 194,489	$ 122,611	$ 126,194	$ 67,492	$ 68,295	$ 55,118
Branch 2							
	1 Phase - 1/0 ACSR	$ 44,168	$ 23,622	$ 44,168	$ 23,622	NA	NA
	3 Phase - 1/0 ACSR	$ 150,321	$ 98,988	$ 82,026	$ 43,870	$ 68,295	$ 55,118
	Total Segments	$ 194,489	$ 122,611	$ 126,194	$ 67,492	$ 68,295	$ 55,118
Branch 3							
	1 Phase - 1/0 ACSR	$ 44,168	$ 23,622	$ 44,168	$ 23,622	NA	NA
	3 Phase - 1/0 ACSR	$ 150,321	$ 98,988	$ 82,026	$ 43,870	$ 68,295	$ 55,118
	Total Segments	$ 194,489	$ 122,611	$ 126,194	$ 67,492	$ 68,295	$ 55,118
Branch 4							
	1 Phase - 1/0 ACSR	$ 44,168	$ 23,622	$ 44,168	$ 23,622	NA	NA
	3 Phase - 1/0 ACSR	$ 150,321	$ 98,988	$ 82,026	$ 43,870	$ 68,295	$ 55,118
	Total Segments	$ 194,489	$ 122,611	$ 126,194	$ 67,492	$ 68,295	$ 55,118
Branch 5							
	1 Phase - 1/0 ACSR	$ 44,168	$ 23,622	$ 44,168	$ 23,622	NA	NA
	3 Phase - 1/0 ACSR	$ 150,321	$ 98,988	$ 82,026	$ 43,870	$ 68,295	$ 55,118
	Total Segments	$ 194,489	$ 122,611	$ 126,194	$ 67,492	$ 68,295	$ 55,118
Branch 6							
	3 Phase - 447 AAC & 4\0 AAC	$ 258,590	$ 328,232	$ 126,194	$ 67,492	$ 132,396	$ 260,740
	Total Segments	$ 258,590	$ 328,232	$ 126,194	$ 67,492	$ 132,396	$ 260,740
Branch 7							
	3 Phase -795 AAC & 477 AAC	$ 269,626	$ 581,174	$ 126,194	$ 67,492	$ 143,432	$ 513,682
	Total segment	$ 269,626	$ 581,174	$ 126,194	$ 67,492	$ 143,432	$ 513,682

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/kW.

Figure 8 – Oregon Poles Demand Calculations, Cost Assignment

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Hypothetical Circuit Branch								
Line		1	2	3	4	5	6	7		
1	% customer	14.64%	14.64%	14.64%	NA	NA	56.09%	NA	100.00%	
2	Branch 6 Cost	$ 19,377	$ 19,377	$ 19,377	NA	NA	$ 74,265	NA	$ 132,396	$ / kW
3	% customer	0.46%	0.46%	0.46%	1.76%	1.76%	1.76%	93.34%	100.00%	
4	Branch 7 Cost	$ 659	$ 659	$ 659	$ 2,526	$ 2,526	$ 2,526	$ 133,879	$ 143,432	
5	Branch Commitment Cost	$ 68,295	$ 68,295	$ 68,295	$ 68,295	$ 68,295	NA	NA		Average
6	Total	$ 88,331	$ 88,331	$ 88,331	$ 70,820	$ 70,820	$ 76,790	$ 133,879	$ 617,302	$ 159.08
7										
8									Total	
9									Demand	$ Per
10	Class Cost per Branch	1	2	3	4	5	6	7	Cost	kW
11	Res - Schedule 4 (sec)	$ 34,252	$ 34,252	$ 34,252	$ 39,114	$ 39,114	$ 42,411	$ 73,162	$ 296,558	$ 140.33
12	GS - Schedule 23 - 0-15 kW (sec)	$ 6,404	$ 6,404	$ 6,404	$ 4,579	$ 4,579	$ 4,965	$ 5,679	$ 39,014	$ 228.45
13	GS - Schedule 23 - 15+ kW (sec)	$ 6,650	$ 6,650	$ 6,650	$ 4,755	$ 4,755	$ 5,156	$ 5,897	$ 40,514	$ 228.45
14	GS - Schedule 23 - Primary (pri)	$ 6	$ 6	$ 6	$ 4	$ 4	$ 5	$ 5	$ 35	$ 228.45
15	GS - Schedule 28 - 0-50 kW (sec)	$ 2,507	$ 2,507	$ 2,507	$ 1,919	$ 1,919	$ 2,081	$ 4,624	$ 18,065	$ 136.67
16	GS - Schedule 28 - 51-100 kW (sec)	$ 4,072	$ 4,072	$ 4,072	$ 3,117	$ 3,117	$ 3,380	$ 7,511	$ 29,343	$ 136.67
17	GS - Schedule 28 - 100 + kW (sec)	$ 5,770	$ 5,770	$ 5,770	$ 4,416	$ 4,416	$ 4,789	$ 10,641	$ 41,572	$ 136.67
18	GS - Schedule 28 - Primary (pri)	$ 157	$ 157	$ 157	$ 120	$ 120	$ 130	$ 289	$ 1,131	$ 136.67
19	GS - Schedule 30 - 0-300 kW (sec)	$ 1,019	$ 1,019	$ 1,019	$ 518	$ 518	$ 561	$ 2,283	$ 6,936	$ 108.56
20	GS - Schedule 30 - 300+ kW (sec)	$ 4,953	$ 4,953	$ 4,953	$ 2,516	$ 2,516	$ 2,728	$ 11,101	$ 33,720	$ 108.56
21	GS - Schedule 30 - Primary (pri)	$ 491	$ 491	$ 491	$ 249	$ 249	$ 271	$ 1,101	$ 3,343	$ 108.56
22	Irrigation - Sch 41	$ 3,009	$ 3,009	$ 3,009	$ 5,031	$ 5,031	$ 5,455	$ 1,677	$ 26,221	$ 424.63
23	LPS - Schedule 48T - 1 - 4 MW (sec)	$ 9,416	$ 9,416	$ 9,416	$ 2,216	$ 2,216	$ 2,403	$ 4,899	$ 39,981	$ 276.37
24	LPS - Schedule 48T - 1 - 4 MW (pri)	$ 9,625	$ 9,625	$ 9,625	$ 2,265	$ 2,265	$ 2,456	$ 5,008	$ 40,869	$ 276.37
25	LPS - Schedule 48T - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48T - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 88,331	$ 88,331	$ 88,331	$ 70,820	$ 70,820	$ 76,790	$ 133,879	$ 617,302	

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								
Line		1	2	3	4	5	6	7		
1	% customer	12.57%	12.57%	12.57%	NA	NA	62.29%	NA	100.00%	
2	Branch 6 Cost	$ -	$ -	$ -	NA	NA	$ -	NA	$ -	$ Per
3	% customer	0.39%	0.39%	0.39%	1.95%	1.95%	1.95%	92.96%	100.00%	Customer
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 126,194	$ 126,194	$ 126,194	$ 126,194	$ 126,194	$ 126,194	$ 126,194		Average
6	Total	$ 126,194	$ 126,194	$ 126,194	$ 126,194	$ 126,194	$ 126,194	$ 126,194	$ 883,359	$ 774.25
7										
8									Total	
9									Commitment	$ Per
10	Class Cost per Branch	1	2	3	4	5	6	7	Cost	Customer
11	Res - Schedule 4 (sec)	$ 87,264	$ 87,264	$ 87,264	$ 96,139	$ 96,139	$ 96,139	$ 105,987	$ 656,196	$ 690.00
12	GS - Schedule 23 - 0-15 kW (sec)	$ 28,128	$ 28,128	$ 28,128	$ 19,403	$ 19,403	$ 19,403	$ 14,184	$ 156,779	$ 1,183.31
13	GS - Schedule 23 - 15+ kW (sec)	$ 4,990	$ 4,990	$ 4,990	$ 3,442	$ 3,442	$ 3,442	$ 2,516	$ 27,813	$ 1,183.31
14	GS - Schedule 23 - Primary (pri)	$ 36	$ 36	$ 36	$ 25	$ 25	$ 25	$ 18	$ 201	$ 1,183.31
15	GS - Schedule 28 - 0-50 kW (sec)	$ 921	$ 921	$ 921	$ 680	$ 680	$ 680	$ 966	$ 5,771	$ 672.71
16	GS - Schedule 28 - 51-100 kW (sec)	$ 725	$ 725	$ 725	$ 536	$ 536	$ 536	$ 761	$ 4,544	$ 672.71
17	GS - Schedule 28 - 100 + kW (sec)	$ 417	$ 417	$ 417	$ 308	$ 308	$ 308	$ 438	$ 2,615	$ 672.71
18	GS - Schedule 28 - Primary (pri)	$ 14	$ 14	$ 14	$ 11	$ 11	$ 11	$ 15	$ 90	$ 672.71
19	GS - Schedule 30 - 0-300 kW (sec)	$ 38	$ 38	$ 38	$ 19	$ 19	$ 19	$ 49	$ 220	$ 518.63
20	GS - Schedule 30 - 300+ kW (sec)	$ 98	$ 98	$ 98	$ 48	$ 48	$ 48	$ 125	$ 566	$ 518.63
21	GS - Schedule 30 - Primary (pri)	$ 9	$ 9	$ 9	$ 5	$ 5	$ 5	$ 12	$ 54	$ 518.63
22	Irrigation - Sch 41	$ 3,443	$ 3,443	$ 3,443	$ 5,553	$ 5,553	$ 5,553	$ 1,091	$ 28,079	$ 2,250.11
23	LPS - Schedule 48T - 1 - 4 MW (sec)	$ 67	$ 67	$ 67	$ 15	$ 15	$ 15	$ 20	$ 266	$ 1,465.45
24	LPS - Schedule 48T - 1 - 4 MW (pri)	$ 42	$ 42	$ 42	$ 10	$ 10	$ 10	$ 12	$ 167	$ 1,465.45
25	LPS - Schedule 48T - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48T - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 126,194	$ 126,194	$ 126,194	$ 126,194	$ 126,194	$ 126,194	$ 126,194	$ 883,359	

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 two-thirds 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 two-thirds of a mile circuit by the customer's kW determines the demand cost in dollars/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	$ 51,103	$ 110,152		$ 51,103	$ 110,152
Average Trunk Length	0.67	miles		0.67	miles
Total Construction Cost	$ 34,239	$ 73,802		$ 34,239	$ 73,802
Customer Peak Demand	4,637	kW		3,599	kW
Demand Cost $/kW	$7.38	$15.92		$9.51	$20.50

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 dollars/customer and dollars/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

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
								=(C)*(F)	=(D)*(F)
		Commitment $/Customer		Demand $/Dist. kW		Typical circuit		Demand $/circuit	
Line	Class	Poles	Conductor	Poles	Conductor	Customers	kW	Poles	Conductor
1	Res - Schedule 4 (sec)	$ 690.00	$ 369.03	$ 140.33	$ 250.75	951.0	2,113.35	$ 296,558	$ 529,926
2	GS - Schedule 23 - 0-15 kW (sec)	$ 1,183.31	$ 632.87	$ 228.45	$ 348.28	132.5	170.78	$ 39,014	$ 59,479
3	GS - Schedule 23 - 15+ kW (sec)	$ 1,183.31	$ 632.87	$ 228.45	$ 348.28	23.5	177.34	$ 40,514	$ 61,765
4	GS - Schedule 23 - Primary (pri)	$ 1,183.31	$ 632.87	$ 228.45	$ 348.28	0.2	0.16	$ 35	$ 54
5	GS - Schedule 28 - 0-50 kW (sec)	$ 672.71	$ 359.78	$ 136.67	$ 245.05	8.6	132.18	$ 18,065	$ 32,391
6	GS - Schedule 28 - 51-100 kW (sec)	$ 672.71	$ 359.78	$ 136.67	$ 245.05	6.8	214.70	$ 29,343	$ 52,612
7	GS - Schedule 28 - 100 + kW (sec)	$ 672.71	$ 359.78	$ 136.67	$ 245.05	3.9	304.17	$ 41,572	$ 74,538
8	GS - Schedule 28 - Primary (pri)	$ 672.71	$ 359.78	$ 136.67	$ 245.05	0.1	8.27	$ 1,131	$ 2,027
9	GS - Schedule 30 - 0-300 kW (sec)	$ 518.63	$ 277.38	$ 108.56	$ 212.23	0.4	63.89	$ 6,936	$ 13,560
10	GS - Schedule 30 - 300+ kW (sec)	$ 518.63	$ 277.38	$ 108.56	$ 212.23	1.1	310.61	$ 33,720	$ 65,921
11	GS - Schedule 30 - Primary (pri)	$ 518.63	$ 277.38	$ 108.56	$ 212.23	0.1	30.80	$ 3,343	$ 6,536
12	Irrigation - Sch 41	$ 2,250.11	$ 1,203.42	$ 424.63	$ 581.83	12.5	61.75	$ 26,221	$ 35,927
13	LPS - Schedule 48T - 1 - 4 MW (sec)	$ 1,465.45	$ 783.76	$ 276.37	$ 394.04	0.2	144.67	$ 39,981	$ 57,005
14	LPS - Schedule 48T - 1 - 4 MW (pri)	$ 1,465.45	$ 783.76	$ 276.37	$ 394.04	0.1	147.88	$ 40,869	$ 58,272
15	Total -	$ 774.25	$ 414.09	$ 159.08	$ 270.58	1,140.9	3,880.5	$ 617,302	$ 1,050,015
16									
17	Large GS + 4 MW (sec)	$ -	$ -	$ 9.51	$ 20.50	-	3,599.23	$ 34,239	$ 73,802
18	Large GS + 4 MW (pri)	$ -	$ -	$ 7.38	$ 15.92	-	4,636.55	$ 34,239	$ 73,802
								$ 685,780	$ 1,197,619
			Commitment	Demand	Total				
		Poles	$ 883,359	$ 685,780	$ 1,569,140				
		Conductor	$ 472,444	$ 1,197,619	$ 1,670,063				
		Total	$ 1,355,804	$ 1,883,399	$ 3,239,203				

Table 1

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Demand & Energy in Mills/kWh
December 2021 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)
			Energy			Demand & Energy		
Line	Description		1 Year	10 Year	20 Year	1 Year	10 Year	20 Year
1	Res - Schedule 4	(sec)	22.80	32.36	36.10	22.80	70.56	74.27
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	22.80	32.36	36.10	22.80	67.05	70.76
5	15+ kW	(sec)	22.80	32.36	36.10	22.80	69.29	73.00
6	Primary	(pri)	22.15	31.44	35.08	22.15	44.06	47.29
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	22.80	32.36	36.10	22.80	63.93	67.64
10	51-100 kW	(sec)	22.80	32.36	36.10	22.80	64.63	68.34
11	100 + kW	(sec)	22.80	32.36	36.10	22.80	65.86	69.57
12	Primary	(pri)	22.15	31.44	35.08	22.15	62.76	66.35
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	22.80	32.36	36.10	22.80	62.88	66.60
16	300+ kW	(sec)	22.80	32.36	36.10	22.80	61.01	64.73
17	Primary	(pri)	22.15	31.44	35.08	22.15	61.41	65.02
18								
19	LPS - Schedule 48							
20	1 - 4 MW	(sec)	22.80	32.36	36.10	22.80	68.04	71.76
21	1 - 4 MW	(pri)	22.15	31.44	35.08	22.15	64.83	68.44
22	> 4 MW	(sec)	22.80	32.36	36.10	22.80	52.64	56.34
23	> 4 MW	(pri)	22.15	31.44	35.08	22.15	50.60	54.21
24	Trans	(trn)	21.66	30.74	34.30	21.66	45.45	48.98
25								
26								
27	Schedule 41- Irrigation	(sec)	22.80	32.36	36.10	22.80	72.56	76.28

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 2021 Dollars

			(A)	(B)
Line	Description		1 Year	10 & 20 Year
1	Res - Schedule 4	(sec)	$12.24	$29.76
2				
3	GS - Schedule 23			
4	0-15 kW	(sec)	13.69	43.84
5	15+ kW	(sec)	22.91	59.71
6	Primary	(pri)	133.37	150.44
7				
8	GS - Schedule 28			
9	0-50 kW	(sec)	25.79	96.53
10	51-100 kW	(sec)	26.61	104.69
11	100 + kW	(sec)	57.35	141.47
12	Primary	(pri)	135.66	145.36
13				
14	GS - Schedule 30			
15	0-300 kW	(sec)	69.87	165.95
16	300+ kW	(sec)	102.53	198.53
17	Primary	(pri)	147.90	155.38
18				
19	LPS - Schedule 48			
20	1 - 4 MW	(sec)	351.26	461.94
21	1 - 4 MW	(pri)	227.10	248.23
22	> 4 MW	(sec)	351.26	440.81
23	> 4 MW	(pri)	227.10	227.10
24	Trans	(trn)	2,008.70	2,008.70
25				
26				
27	Schedule 41- Irrigation	(sec)	7.38	110.77

Footnote:
Short-run commitment and billing costs include the cost of metering, meter overhead, maintenance, service drops, service drop overhead and maintenance, customer accounting, informational expenses, and billing expenses.

Table 3

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost
December 2021 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)	(R)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41	Lighting
						0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn		Schs 15, 51,
Line	Calculation Component	Class	Units Description / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	53, 54 (sec)
1	Units	Demand	Peak MW @ Input-System		1,059	94	93	0	72	112	158	4	33	167	16	80	80	8	137	119	32	
2	Units	Demand	Peak MW @ Input-Distribution		1,246	101	105	0	78	127	179	5	38	183	18	85	85	8	143	-	36	
3	Units	Demand	Peak MW @ Input-Transformer		3,667	280	180	-	145	261	327	-	48	308	-	127	-	15	-	-	172	
4																						
5	Units	Energy	Annual MWh @ Input		6,073,571	640,227	600,708	2,230	475,342	738,335	1,000,481	27,758	218,305	1,171,819	104,494	549,985	563,712	60,722	1,086,519	1,025,434	243,723	
6																						
7	Units	Customer	Average		517,740	70,266	12,466	90	4,681	3,686	2,121	73	231	593	56	97	60	2	29	7	4,803	
8	Units	Customer	Annual		517,740	70,266	12,466	90	4,681	3,686	2,121	73	231	593	56	97	60	2	29	7	7,894	
9																						
10																						
11	$/Unit	Demand	Generation ($/System Peak kW)		$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	$117.73	
12	$/Unit	Demand	Transmission ($/System Peak kW)		$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	
13	$/Unit	Demand	Dist-Poles ($/Dist. kW)		$15.82	$25.75	$25.75	$25.75	$15.42	$15.42	$15.42	$15.42	$12.24	$12.24	$12.24	$31.16	$31.16	$1.07	$0.83	$0.00	$47.88	
14	$/Unit	Demand	Dist-Cond ($/Dist. kW)		$28.27	$39.28	$39.28	$39.28	$27.63	$27.63	$27.63	$27.63	$23.93	$23.93	$23.93	$44.43	$44.43	$2.32	$1.79	$0.00	$65.60	
15	$/Unit	Demand	Dist-Substation ($/Dist. kW)		$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$0.00	$17.09	
16	$/Unit	Demand	Dist-Transformers ($/Xfmr kW)		$1.64	$1.64	$1.64	$0.00	$1.64	$1.64	$1.64	$0.00	$1.64	$1.64	$0.00	$1.64	$0.00	$1.64	$0.00	$0.00	$1.64	
17																						
18	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	
19	$/Unit	Energy	Transmission Energy @ Input ($/kWh)		$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	
20																						
21	$/Unit	Customer	Dist-Poles ($/Customer)		$77.80	$133.42	$133.42	$133.42	$75.85	$75.85	$75.85	$75.85	$58.47	$58.47	$58.47	$165.23	$165.23	$0.00	$0.00	$0.00	$253.70	
22	$/Unit	Customer	Dist-Conductor ($/Customer)		$41.61	$71.36	$71.36	$71.36	$40.57	$40.57	$40.57	$40.57	$31.28	$31.28	$31.28	$88.37	$88.37	$0.00	$0.00	$0.00	$135.68	
23	$/Unit	Customer	Dist-Transformers ($/Customer)		$90.81	$157.04	$236.88	$0.00	$732.51	$820.56	$893.09	$0.00	$1,063.23	$1,062.30	$0.00	$1,074.63	$0.00	$1,074.63	$0.00	$0.00	$851.21	
24	$/Unit	Customer	Dist-Service Drop ($/Customer)		$77.37	$100.00	$204.93	$0.00	$208.98	$216.56	$423.48	$0.00	$425.86	$817.80	$0.00	$2,803.50	$0.00	$2,803.50	$0.00	$0.00	$0.00	
25	$/Unit	Customer	Meters ($/Customer)		$24.63	$26.15	$31.77	$1,562.31	$34.89	$37.17	$199.09	$1,562.31	$200.01	$199.99	$1,562.31	$248.70	$1,562.31	$248.70	$1,562.31	$22,941.49	$37.54	
26	$/Unit	Customer	Meter Reading ($/Customer)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
27	$/Unit	Customer	Billing & Collections ($/Customer)		$28.14	$27.86	$27.86	$27.86	$30.57	$30.57	$30.57	$30.57	$30.57	$30.57	$30.57	$139.32	$139.32	$139.32	$139.32	$139.32	$22.08	
28	$/Unit	Customer	Uncollectables ($/Customer)		$8.52	$2.31	$2.31	$2.31	$25.98	$25.98	$25.98	$25.98	$167.19	$167.19	$167.19	$971.88	$971.88	$971.88	$971.88	$971.88	$20.49	
29	$/Unit	Customer	Customer Service / Other ($/Customer)		$8.26	$8.00	$8.00	$8.00	$9.06	$9.06	$9.06	$9.06	$14.77	$14.77	$14.77	$51.70	$51.70	$51.70	$51.70	$51.70	$8.50	
30																						
31																						
32	$000	Demand	Generation	$266,496	$124,692	$11,107	$10,934	$18	$8,447	$13,198	$18,553	$511	$3,849	$19,633	$1,927	$9,424	$9,447	$901	$16,126	$13,976	$3,752	$0
33	$000	Demand	Transmission	$8,194	$3,834	$342	$336	$1	$260	$406	$570	$16	$118	$604	$59	$290	$290	$28	$496	$430	$115	$0
34	$000	Demand	Dist-Poles	$41,148	$19,712	$2,593	$2,693	$2	$1,202	$1,952	$2,765	$73	$461	$2,242	$216	$2,658	$2,641	$9	$119	$0	$1,744	$67
35	$000	Demand	Dist-Conductor	$70,065	$35,232	$3,956	$4,108	$3	$2,153	$3,498	$4,955	$131	$902	$4,384	$422	$3,790	$3,765	$19	$256	$0	$2,389	$102
36	$000	Demand	Dist-Substations	$41,626	$21,293	$1,721	$1,787	$2	$1,332	$2,163	$3,065	$81	$644	$3,130	$302	$1,458	$1,448	$137	$2,444	$0	$622	$0
37	$000	Demand	Dist-Transformers	$9,080	$6,001	$458	$294	$0	$237	$427	$535	$0	$79	$505	$0	$208	$0	$25	$0	$0	$281	$29
38	$000	Demand	Total Demand	$436,610	$210,765	$20,176	$20,152	$25	$13,630	$21,643	$30,445	$812	$6,053	$30,497	$2,926	$17,829	$17,591	$1,118	$19,441	$14,405	$8,903	$198
39																						
40	$000	Energy	Generation	$479,116	$199,213	$20,999	$19,703	$73	$15,591	$24,217	$32,816	$910	$7,160	$38,436	$3,427	$18,040	$18,490	$1,992	$35,638	$33,634	$7,994	$782
41	$000	Energy	Transmission	$190	$79	$8	$8	$0	$6	$10	$13	$0	$3	$15	$1	$7	$7	$1	$14	$13	$3	$0
42	$000	Energy	Total Energy	$479,306	$199,292	$21,008	$19,711	$73	$15,597	$24,227	$32,829	$911	$7,163	$38,451	$3,429	$18,047	$18,497	$1,992	$35,652	$33,648	$7,997	$782
43																						
44	$000	Customer	Dist-Poles	$54,210	$40,278	$9,375	$1,663	$12	$355	$280	$161	$6	$14	$35	$3	$16	$10	$0	$0	$0	$2,003	$0
45	$000	Customer	Dist-Conductor	$28,994	$21,544	$5,014	$890	$6	$190	$150	$86	$3	$7	$19	$2	$9	$5	$0	$0	$0	$1,071	$0
46	$000	Customer	Dist-Transformers	$77,051	$47,015	$11,034	$2,953	$0	$3,429	$3,025	$1,894	$0	$246	$630	$0	$104	$0	$2	$0	$0	$6,719	$0
47	$000	Customer	Dist-Lighting	$5,235	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,235
48	$000	Customer	Dist-Service Drop	$53,173	$40,056	$7,026	$2,555	$0	$978	$798	$898	$0	$98	$485	$0	$272	$0	$6	$0	$0	$0	$0
49	$000	Customer	Meters	$16,840	$12,753	$1,838	$396	$141	$163	$137	$422	$114	$46	$119	$87	$24	$94	$0	$45	$161	$296	$2.75
50	$000	Customer	Meter Reading	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	$000	Customer	Billing & Collections	$17,549	$14,567	$1,958	$347	$3	$143	$113	$65	$2	$7	$18	$2	$14	$8	$0	$4	$1	$106	$191
52	$000	Customer	Uncollectables	$5,313	$4,413	$162	$29	$0	$122	$96	$55	$2	$39	$99	$9	$94	$58	$2	$28	$7	$98	$0
53	$000	Customer	Customer Service / Other	$5,156	$4,275	$562	$100	$1	$42	$33	$19	$1	$3	$9	$1	$5	$3	$0	$1	$0	$41	$59
54	$000	Customer	Total Customer (Commitment & Billing)	$263,521	$184,902	$36,969	$8,932	$162	$5,423	$4,631	$3,601	$127	$460	$1,413	$104	$538	$179	$11	$79	$169	$10,335	$5,488
55																						
56																						
57			Total Revenue @ Full MC ($000)																			
58			Generation	$745,612	$323,906	$32,106	$30,638	$91	$24,038	$37,415	$51,369	$1,422	$11,009	$58,069	$5,355	$27,464	$27,936	$2,893	$51,764	$47,610	$11,746	$782
59			Transmission	$8,384	$3,913	$350	$344	$1	$266	$415	$583	$16	$121	$619	$61	$297	$298	$29	$510	$443	$119	$0
60			Distribution	$375,348	$231,131	$41,178	$16,942	$26	$9,876	$12,291	$14,360	$294	$2,450	$11,428	$945	$8,516	$7,869	$196	$2,819	$0	$14,829	$198
61			Distribution-Lighting	$5,235	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,235
62			Customer - Billing	$17,549	$14,567	$1,958	$347	$3	$143	$113	$65	$2	$7	$18	$2	$14	$8	$0	$4	$1	$106	$191
63			Customer - Metering	$16,840	$12,753	$1,838	$396	$141	$163	$137	$422	$114	$46	$119	$87	$24	$94	$0	$45	$161	$296	$3
64			Customer - Other	$5,156	$4,275	$562	$100	$1	$42	$33	$19	$1	$3	$9	$1	$5	$3	$0	$1	$0	$41	$59
65			Total Revenue (less Uncollectables)	$1,174,124	$590,546	$77,991	$48,767	$261	$34,529	$50,405	$66,819	$1,848	$13,637	$70,261	$6,450	$36,319	$36,208	$3,119	$55,144	$48,215	$27,137	$6,468
66																						
67			Customer - Uncollectables	$5,313	$4,413	$162	$29	$0	$122	$96	$55	$2	$39	$99	$9	$94	$58	$2	$28	$7	$98	$0
68			Total Revenue	$1,179,437	$594,959	$78,153	$48,795	$261	$34,650	$50,501	$66,874	$1,850	$13,676	$70,360	$6,460	$36,413	$36,267	$3,121	$55,172	$48,222	$27,235	$6,468

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)
2021	39.68	20.72	18.96	117.10
2022	43.88	24.44	19.44	120.05
2023	48.40	28.50	19.90	122.90
2024	52.85	32.49	20.36	125.77
2025	56.02	35.18	20.84	128.69
2026	58.17	36.86	21.31	131.62
2027	58.56	36.78	21.78	134.52
2028	58.80	36.55	22.25	137.44
2029	61.80	39.06	22.74	140.44
2030	66.36	43.12	23.24	143.51
2031	69.21	45.48	23.73	146.58
2032	72.08	47.85	24.23	149.66
2033	74.96	50.22	24.74	152.77
2034	77.78	52.53	25.25	155.92
2035	76.26	50.50	25.76	159.11
2036	77.33	51.04	26.29	162.36
2037	80.44	53.62	26.82	165.64
2038	84.59	57.23	27.36	168.95
2039	88.60	60.70	27.90	172.33
2040	90.94	62.48	28.46	175.78

	Mills/kWh	Mills/kWh	Mills/kWh	$/kW
2021 (1 Year)	39.68	20.72	18.96	117.10
2021 - 2025 (5 Year, Short Run)				
Sum of PV Costs @ 7.68%	206.18	120.20	85.98	531.06
Annual Cost @ 22.15%	45.66	26.62	19.04	117.63
2021 - 2030 (10 Year, Medium Run)				
Sum of PV Costs @ 7.68%	387.26	234.81	152.45	941.68
Annual Cost @ 12.52%	48.49	29.40	19.09	117.90
2021 - 2040 (20 Year, Long Run)				
Sum of PV Costs @ 7.68%	659.81	417.30	242.51	1,497.90
Annual Cost @ 7.86%	51.86	32.80	19.06	117.73

Table 5

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost of
Transmission Investment and Associated Expenses

Line	Item	$	
1	Growth Related Investments - (2020 to 2024 in $000s)	$135,731	
2			
3	System Growth MW from 2020 to 2024	3,204	
4			
5	Marginal Investment (line 1/line 3)	$42.36	/ kW
6			
7	Annualized Investment @ 6.86%	2.91	/ kW
8	Admin. & General Factor @ 0.61%	0.26	
9	Annual O&M Expenses @ 1.275%	0.54	/ kW
10	Annualized Marginal Cost	$3.71	/ kW
11			
12	Marginal Cost of Demand-Related Transmission	$3.62	/ kW
13			
14	Marginal Cost of Energy-Related Transmission (Line 10 - Line 12)	$0.09	/ kW
15	Marginal Cost of Energy-Related Transmission	$0.00001	/ kWh
16	$0.09 / (8760 x 79.03% LF))		

Table 6

PacifiCorp
Oregon Marginal Cost Study
Marginal Distribution & Billing Costs
2021 Dollars

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
		Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg Sch 41
			0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans	
Line	Description	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
1	Demand Costs ($/kW)																	
2																		
3	Dist-Poles	$11.05	$17.99	$17.99	$17.99	$10.77	$10.77	$10.77	$10.77	$8.55	$8.55	$8.55	$21.77	$21.77	$0.75	$0.58	$0.00	$33.45
4	Dist-Conductors	$19.75	$27.44	$27.44	$27.44	$19.30	$19.30	$19.30	$19.30	$16.72	$16.72	$16.72	$31.04	$31.04	$1.62	$1.25	$0.00	$45.83
5	Dist-Substation	$11.94	$11.94	$11.94	$11.94	$11.94	$11.94	$11.94	$11.94	$11.94	$11.94	$11.94	$11.94	$11.94	$11.94	$11.94	$0.00	$11.94
6	Dist. O&M @ 43.14% of Investment	$18.44	$24.75	$24.75	$24.75	$18.12	$18.12	$18.12	$18.12	$16.05	$16.05	$16.05	$27.93	$27.93	$6.17	$5.94	$0.00	$39.35
7	Total $/Dist. kW	$61.17	$82.11	$82.11	$82.11	$60.13	$60.13	$60.13	$60.13	$53.26	$53.26	$53.26	$92.68	$92.68	$20.48	$19.71	$0.00	$130.57
8																		
9	Dist-Transformers	$1.14	$1.14	$1.14	$0.00	$1.14	$1.14	$1.14	$0.00	$1.14	$1.14	$0.00	$1.14	$0.00	$1.14	$0.00	$0.00	$1.14
10	Dist. O&M @ 43.14% of Investment	$0.49	$0.49	$0.49	$0.00	$0.49	$0.49	$0.49	$0.00	$0.49	$0.49	$0.00	$0.49	$0.00	$0.49	$0.00	$0.00	$0.49
11	Total $/Transformer kW	$1.64	$1.64	$1.64	$0.00	$1.64	$1.64	$1.64	$0.00	$1.64	$1.64	$0.00	$1.64	$0.00	$1.64	$0.00	$0.00	$1.64
12																		
13																		
14																		
15	Customer Costs ($/Customer)																	
16																		
17	Commitment																	
18	Dist-Poles	$54.35	$93.21	$93.21	$93.21	$52.99	$52.99	$52.99	$52.99	$40.85	$40.85	$40.85	$115.43	$115.43	$0.00	$0.00	$0.00	$177.24
19	Dist-Conductors	$29.07	$49.85	$49.85	$49.85	$28.34	$28.34	$28.34	$28.34	$21.85	$21.85	$21.85	$61.74	$61.74	$0.00	$0.00	$0.00	$94.79
20	Dist-Transformers	$63.44	$109.71	$165.49	$0.00	$511.74	$573.26	$623.93	$0.00	$742.79	$742.14	$0.00	$750.75	$0.00	$750.75	$0.00	$0.00	$594.67
21	Dist. O&M @ 43.14% of Investment	$63.36	$109.04	$133.11	$61.72	$255.85	$282.39	$304.25	$35.09	$347.49	$347.21	$27.05	$400.31	$76.43	$323.87	$0.00	$0.00	$373.89
22	Total Commitment	$210.22	$361.81	$441.65	$204.78	$848.92	$936.98	$1,009.51	$116.42	$1,152.98	$1,152.05	$89.75	$1,328.23	$253.60	$1,074.63	$0.00	$0.00	$1,240.59
23	Monthly Commitment	$17.52	$30.15	$36.80	$17.06	$70.74	$78.08	$84.13	$9.70	$96.08	$96.00	$7.48	$110.69	$21.13	$89.55	$0.00	$0.00	$103.38
24																		
25	Billing																	
26	Dist-Service Drop	$54.05	$69.86	$143.17	$0.00	$146.00	$151.29	$295.85	$0.00	$297.51	$571.33	$0.00	$1,958.57	$0.00	$1,958.57	$0.00	$0.00	$0.00
27	Dist. O&M @ 43.14% of Investment	$23.32	$30.14	$61.76	$0.00	$62.98	$65.27	$127.63	$0.00	$128.35	$246.47	$0.00	$844.93	$0.00	$844.93	$0.00	$0.00	$0.00
28	Meter	$13.95	$14.81	$17.99	$884.76	$19.76	$21.05	$112.75	$884.76	$113.27	$113.26	$884.76	$140.84	$884.76	$140.84	$884.76	$12,992.12	$21.26
29	Meter O&M @ 76.58% of Investment	$10.68	$11.34	$13.78	$677.55	$15.13	$16.12	$86.34	$677.55	$86.74	$86.73	$677.55	$107.86	$677.55	$107.86	$677.55	$9,949.37	$16.28
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	$28.14	$27.86	$27.86	$27.86	$30.57	$30.57	$30.57	$30.57	$30.57	$30.57	$30.57	$139.32	$139.32	$139.32	$139.32	$139.32	$22.08
32	Uncollectables	$8.52	$2.31	$2.31	$2.31	$25.98	$25.98	$25.98	$25.98	$167.19	$167.19	$167.19	$971.88	$971.88	$971.88	$971.88	$971.88	$20.49
33	Customer Service / Other	$8.26	$8.00	$8.00	$8.00	$9.06	$9.06	$9.06	$9.06	$14.77	$14.77	$14.77	$51.70	$51.70	$51.70	$51.70	$51.70	$8.50
34	Total Billing	$146.92	$164.31	$274.86	$1,600.47	$309.49	$319.34	$688.18	$1,627.92	$838.40	$1,230.32	$1,774.84	$4,215.10	$2,725.21	$4,215.10	$2,725.21	$24,104.39	$88.60
35	Monthly Billing	$12.24	$13.69	$22.91	$133.37	$25.79	$26.61	$57.35	$135.66	$69.87	$102.53	$147.90	$351.26	$227.10	$351.26	$227.10	$2,008.70	$7.38
36																		
37	Total Customer (Commitment & Billing)	$357.13	$526.13	$716.52	$1,805.25	$1,158.41	$1,256.31	$1,697.69	$1,744.34	$1,991.38	$2,382.37	$1,864.59	$5,543.33	$2,978.82	$5,289.73	$2,725.21	$24,104.39	$1,329.19
38	Monthly Customer (Commitment & Billing)	$29.76	$43.84	$59.71	$150.44	$96.53	$104.69	$141.47	$145.36	$165.95	$198.53	$155.38	$461.94	$248.23	$440.81	$227.10	$2,008.70	$110.77
39																		

Table 7

PacifiCorp
Oregon Marginal Cost Study
20 Year Demand Costs Divided by Billing kW
December 2021 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41
				0-15 kW	15+ kW		0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn	
Line	Units Description / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
1	Marginal Cost ($000)																		
2																			
3	Generation	$266,496	$124,692	$11,107	$10,934	$18	$8,447	$13,198	$18,553	$511	$3,849	$19,633	$1,927	$9,424	$9,447	$901	$16,126	$13,976	$3,752
4	Transmission	$8,194	$3,834	$342	$336	$1	$260	$406	$570	$16	$118	$604	$59	$290	$290	$28	$496	$430	$115
5	Dist-Poles, Wire, Sub	$152,671	$76,238	$8,270	$8,588	$7	$4,687	$7,613	$10,785	$285	$2,007	$9,755	$940	$7,906	$7,854	$164	$2,819	$0	$4,754
6	Dist-Transformers	$9,051	$6,001	$458	$294	$0	$237	$427	$535	$0	$79	$505	$0	$208	$0	$25	$0	$0	$281
7																			
8	Average Billing kW @ Sales	7,265,060	4,927,873	360,259	231,213	812	130,267	234,791	294,519	6,851	43,526	277,617	30,818	114,669	115,367	13,742	194,774	133,201	154,759
9																			
10	Generation ($/kW)		$25.30	$30.83	$47.29	$21.70	$64.84	$56.21	$63.00	$74.60	$88.42	$70.72	$62.54	82.19	81.88	65.59	82.79	104.92	24.24
11	Transmission ($/kW)		$0.78	$0.95	$1.45	$0.67	$1.99	$1.73	$1.94	$2.29	$2.72	$2.17	$1.92	2.53	2.52	2.02	2.55	3.23	0.75
12	Dist-Poles, Wire, Sub ($/kW)		$15.47	$22.96	$37.14	$9.00	$35.98	$32.42	$36.62	$41.60	$46.10	$35.14	$30.50	68.95	68.08	11.91	14.47	0.00	30.72
13	Dist-Transformers ($/kW)		$1.22	$1.27	$1.27	$0.00	$1.82	$1.82	$1.82	$0.00	$1.82	$1.82	$0.00	1.82	0.00	1.82	0.00	0.00	1.82
14																			
15	Total Demand Related		$42.77	$56.00	$87.16	$31.37	$104.63	$92.18	$103.37	$118.50	$139.06	$109.85	$94.96	$155.48	$152.48	$81.34	$99.81	$108.15	$57.53
16	Monthly Demand Related		$3.56	$4.67	$7.26	$2.61	$8.72	$7.68	$8.61	$9.87	$11.59	$9.15	$7.91	$12.96	$12.71	$6.78	$8.32	$9.01	$4.79

Table 8

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost Percentage
December 2021 Dollars

Line	Description	(A) Marginal Cost (000s)	(B) Mills / kWh	(C) % of Total
1	Demand Related Marginal Cost			
2	Generation	$266,496	19.93	22.7%
3	Transmission	$8,194	0.61	0.7%
4	Dist. Poles, Cond., Subst.	$152,671	11.42	13.0%
5	Dist. Transformers	$9,080	0.68	0.8%
6	Total Demand Related	$436,441	32.64	37.2%
7				
8	Energy Related Marginal Cost			
9	Generation	$479,116	35.82	40.8%
10	Transmission	$190	0.01	0.0%
11	Total Energy Related	$479,306	35.83	40.8%
12				
13	Commitment & Billing			
14	Commitment	$160,255	11.98	13.6%
15	Billing	$98,031	7.33	8.3%
16	Total Commitment & Billing	$258,286	19.31	22.0%
17				
18				
19	TOTAL MARGINAL COST	$1,174,033	87.78	100.0%
20				
21				
22		Note: Total MWh @ Sales =	13,374,494	

PacifiCorp
Oregon Marginal Cost Study
10 Year Marginal Cost
December 2021 Dollars

					(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41
	Calculation					0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn	
Line	Component	Class	Units Description / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
1	Units	Demand	Peak MW @ Input-System		1,059	94	93	0	72	112	158	4	33	167	16	80	80	8	137	119	32
2	Units	Demand	Peak MW @ Input-Distribution		1,246	101	105	0	78	127	179	5	38	183	18	85	85	8	143	-	36
3	Units	Demand	Peak MW @ Input-Transformer		3,667	280	180	-	145	261	327	-	48	308	-	127	-	15	-	-	172
4																					
5	Units	Energy	Annual MWh @ Input		6,073,571	640,227	600,708	2,230	475,342	738,335	1,000,481	27,758	218,305	1,171,819	104,494	549,985	563,712	60,722	1,086,519	1,025,434	243,723
6																					
7	Units	Customer	Average		517,740	70,266	12,466	90	4,681	3,686	2,121	73	231	593	56	97	60	2	29	7	4,803
8	Units	Customer	Annual		517,740	70,266	12,466	90	4,681	3,686	2,121	73	231	593	56	97	60	2	29	7	7,894
9																					
10																					
11	$/Unit	Demand	Generation ($/System Peak kW)		$117.90	$117.90	$117.90	$117.90	$117.90	$117.90	$117.90	$117.90	$117.90	$117.90	$117.90	$117.90	$117.90	$117.90	$117.90	$117.90	$117.90
12	$/Unit	Demand	Transmission ($/System Peak kW)		$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62	$3.62
13	$/Unit	Demand	Dist-Poles ($/Dist. kW)		$15.82	$25.75	$25.75	$25.75	$15.42	$15.42	$15.42	$15.42	$12.24	$12.24	$12.24	$31.16	$31.16	$1.07	$0.83	$0.00	$47.88
14	$/Unit	Demand	Dist-Cond ($/Dist. kW)		$28.27	$39.28	$39.28	$39.28	$27.63	$27.63	$27.63	$27.63	$23.93	$23.93	$23.93	$44.43	$44.43	$2.32	$1.79	$0.00	$65.60
15	$/Unit	Demand	Dist-Substation ($/Dist. kW)		$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$17.09	$0.00	$17.09
16	$/Unit	Demand	Dist-Transformers ($/Xfmr kW)		$1.64	$1.64	$1.64	$0.00	$1.64	$1.64	$1.64	$0.00	$1.64	$1.64	$0.00	$1.64	$0.00	$1.64	$0.00	$0.00	$1.64
17																					
18	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.02941	$0.02941	$0.02941	$0.02941	$0.02941	$0.02941	$0.02941	$0.02941	$0.02941	$0.02941	$0.02941	$0.02941	$0.02941	$0.02941	$0.02941	$0.02941	$0.02941
19																					
20																					
21	$/Unit	Customer	Dist-Poles ($/Customer)		$77.80	$133.42	$133.42	$133.42	$75.85	$75.85	$75.85	$75.85	$58.47	$58.47	$58.47	$165.23	$165.23	$0.00	$0.00	$0.00	$253.70
22	$/Unit	Customer	Dist-Conductor ($/Customer)		$41.61	$71.36	$71.36	$71.36	$40.57	$40.57	$40.57	$40.57	$31.28	$31.28	$31.28	$88.37	$88.37	$0.00	$0.00	$0.00	$135.68
23	$/Unit	Customer	Dist-Transformers ($/Customer)		$90.81	$157.04	$236.88	$0.00	$732.51	$820.56	$893.09	$0.00	$1,063.23	$1,062.30	$0.00	$1,074.63	$0.00	$1,074.63	$0.00	$0.00	$851.21
24	$/Unit	Customer	Dist-Service Drop ($/Customer)		$77.37	$100.00	$204.93	$0.00	$208.98	$216.56	$423.48	$0.00	$425.86	$817.80	$0.00	$2,803.50	$0.00	$2,803.50	$0.00	$0.00	$0.00
25	$/Unit	Customer	Meters ($/Customer)		$24.63	$26.15	$31.77	$1,562.31	$34.89	$37.17	$199.09	$1,562.31	$200.01	$199.99	$1,562.31	$248.70	$1,562.31	$248.70	$1,562.31	$22,941.49	$37.54
26	$/Unit	Customer	Meter Reading ($/Customer)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
27	$/Unit	Customer	Billing & Collections ($/Customer)		$28.14	$27.86	$27.86	$27.86	$30.57	$30.57	$30.57	$30.57	$30.57	$30.57	$30.57	$139.32	$139.32	$139.32	$139.32	$139.32	$22.08
28	$/Unit	Customer	Uncollectables ($/Customer)		$8.52	$2.31	$2.31	$2.31	$25.98	$25.98	$25.98	$25.98	$167.19	$167.19	$167.19	$971.88	$971.88	$971.88	$971.88	$971.88	$20.49
29	$/Unit	Customer	Customer Service / Other ($/Customer)		$8.26	$8.00	$8.00	$8.00	$9.06	$9.06	$9.06	$9.06	$14.77	$14.77	$14.77	$51.70	$51.70	$51.70	$51.70	$51.70	$8.50
30																					
31																					
32	$000	Demand	Generation	$266,881	$124,872	$11,123	$10,950	$18	$8,459	$13,217	$18,580	$512	$3,854	$19,662	$1,930	$9,438	$9,460	$903	$16,150	$13,996	$3,757
33	$000	Demand	Transmission	$8,195	$3,834	$342	$336	$1	$260	$406	$570	$16	$118	$604	$59	$290	$290	$28	$496	$430	$115
34	$000	Demand	Dist-Poles	$41,082	$19,712	$2,593	$2,693	$2	$1,202	$1,952	$2,765	$73	$461	$2,242	$216	$2,658	$2,641	$9	$119	$0	$1,744
35	$000	Demand	Dist-Conductor	$69,963	$35,232	$3,956	$4,108	$3	$2,153	$3,498	$4,955	$131	$902	$4,384	$422	$3,790	$3,765	$19	$256	$0	$2,389
36	$000	Demand	Dist-Substations	$41,626	$21,293	$1,721	$1,787	$2	$1,332	$2,163	$3,065	$81	$644	$3,130	$302	$1,458	$1,448	$137	$2,444	$0	$622
37	$000	Demand	Dist-Transformers	$9,051	$6,001	$458	$294	$0	$237	$427	$535	$0	$79	$505	$0	$208	$0	$25	$0	$0	$281
38	$000	Demand	Total Demand	$436,797	$210,944	$20,193	$20,168	$26	$13,643	$21,662	$30,471	$813	$6,058	$30,526	$2,929	$17,843	$17,604	$1,120	$19,465	$14,426	$8,908
39																					
40	$000	Energy	Generation	$428,940	$178,642	$18,831	$17,669	$66	$13,981	$21,717	$29,427	$816	$6,421	$34,467	$3,073	$16,177	$16,580	$1,786	$31,958	$30,161	$7,169
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	$428,940	$178,642	$18,831	$17,669	$66	$13,981	$21,717	$29,427	$816	$6,421	$34,467	$3,073	$16,177	$16,580	$1,786	$31,958	$30,161	$7,169
43																					
44	$000	Customer	Dist-Poles	$54,210	$40,278	$9,375	$1,663	$12	$355	$280	$161	$6	$14	$35	$3	$16	$10	$0	$0	$0	$2,003
45	$000	Customer	Dist-Conductor	$28,994	$21,544	$5,014	$890	$6	$190	$150	$86	$3	$7	$19	$2	$9	$5	$0	$0	$0	$1,071
46	$000	Customer	Dist-Transformers	$77,051	$47,015	$11,034	$2,953	$0	$3,429	$3,025	$1,894	$0	$246	$630	$0	$104	$0	$2	$0	$0	$6,719
47	$000	Customer	Dist-Service Drop	$53,173	$40,056	$7,026	$2,555	$0	$978	$798	$898	$0	$98	$485	$0	$272	$0	$6	$0	$0	$0
48	$000	Customer	Meters	$16,837	$12,753	$1,838	$396	$141	$163	$137	$422	$114	$46	$119	$87	$24	$94	$0	$45	$161	$296
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	$17,358	$14,567	$1,958	$347	$3	$143	$113	$65	$2	$7	$18	$2	$14	$8	$0	$4	$1	$106
51	$000	Customer	Uncollectables	$5,313	$4,413	$162	$29	$0	$122	$96	$55	$2	$39	$99	$9	$94	$58	$2	$28	$7	$98
52	$000	Customer	Customer Service / Other	$5,097	$4,275	$562	$100	$1	$42	$33	$19	$1	$3	$9	$1	$5	$3	$0	$1	$0	$41
53	$000	Customer	Total Customer (Commitment & Billing)	$258,033	$184,902	$36,969	$8,932	$162	$5,423	$4,631	$3,601	$127	$460	$1,413	$104	$538	$179	$11	$79	$169	$10,335
54																					
55																					
56			Total Revenue @ Full MC ($000)	$1,123,771	$574,488	$75,993	$46,768	$254	$33,046	$48,010	$63,499	$1,757	$12,939	$66,405	$6,107	$34,557	$34,363	$2,916	$51,501	$44,756	$26,411

PacifiCorp
Oregon Marginal Cost Study
5 Year Marginal Costs
December 2021 Dollars

					(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41
	Calculation					0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn	
Line	Component	Class	Units Description / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
1	Units	Demand	Peak MW @ Input-System		1,059	94	93	0	72	112	158	4	33	167	16	80	80	8	137	119	32
2	Units	Energy	Annual MWh @ Input		6,073,571	640,227	600,708	2,230	475,342	738,335	1,000,481	27,758	218,305	1,171,819	104,494	549,985	563,712	60,722	1,086,519	1,025,434	243,723
3	Units	Customer	Average		517,740	70,266	12,466	90	4,681	3,686	2,121	73	231	593	56	97	60	2	29	7	4,803
4	Units	Customer	Annual		517,740	70,266	12,466	90	4,681	3,686	2,121	73	231	593	56	97	60	2	29	7	7,894
5																					
6																					
7	$/Unit	Demand	Generation ($/System Peak kW)		$117.63	$117.63	$117.63	117.63	$117.63	117.63	$117.63	$117.63	$117.63	$117.63	$117.63	$117.63	$117.63	$117.63	$117.63	$117.63	$117.63
8	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662
9	$/Unit	Customer	Dist-Service Drop ($/Customer)		$77.37	$100.00	$204.93	$0.00	$208.98	$216.56	$423.48	$0.00	$425.86	$817.80	$0.00	$2,803.50	$0.00	$2,803.50	$0.00	$0.00	$0.00
10	$/Unit	Customer	Meters ($/Customer)		$24.63	$26.15	$31.77	$1,562.31	$34.89	$37.17	$199.09	$1,562.31	$200.01	$199.99	$1,562.31	$248.70	$1,562.31	$248.70	$1,562.31	$22,941.49	$37.54
11	$/Unit	Customer	Meter Reading ($/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	$/Unit	Customer	Billing & Collections ($/Customer)		$28.14	$27.86	$27.86	$27.86	$30.57	$30.57	$30.57	$30.57	$30.57	$30.57	$30.57	$139.32	$139.32	$139.32	$139.32	$139.32	$22.08
13	$/Unit	Customer	Uncollectables ($/Customer)		$8.52	$2.31	$2.31	$2.31	$25.98	$25.98	$25.98	$25.98	$167.19	$167.19	$167.19	$971.88	$971.88	$971.88	$971.88	$971.88	$20.49
14	$/Unit	Customer	Customer Service / Other ($/Customer)		$8.26	$8.00	$8.00	$8.00	$9.06	$9.06	$9.06	$9.06	$14.77	$14.77	$14.77	$51.70	$51.70	$51.70	$51.70	$51.70	$8.50
15																					
16																					
17	($000)	Demand	Total Demand	$266,269	$124,587	$11,097	$10,925	$18	$8,440	$13,187	$18,538	$511	$3,845	$19,617	$1,926	$9,416	$9,439	$901	$16,113	$13,964	$3,749
18	($000)	Energy	Total Energy	$388,209	$161,678	$17,043	$15,991	$59	$12,654	$19,654	$26,633	$739	$5,811	$31,194	$2,782	$14,641	$15,006	$1,616	$28,923	$27,297	$6,488
19	($000)	Customer	Total Customer (Billing)	$97,778	$76,065	$11,546	$3,426	$144	$1,449	$1,177	$1,460	$119	$194	$730	$99	$409	$164	$8	$79	$169	$542
20			Total Revenue @ Full MC ($000)	$752,256	$362,330	$39,686	$30,342	$221	$22,542	$34,018	$46,630	$1,368	$9,850	$51,540	$4,807	$24,466	$24,608	$2,525	$45,115	$41,430	$10,778

1 Year MC

PacifiCorp
Oregon Marginal Cost Study
1 Year Marginal Costs
December 2021 Dollars

					(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41
	Calculation					0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn	
Line	Component	Class	Units Description / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
1	Units	Energy	Annual MWh @ Input		6,073,571	640,227	600,708	2,230	475,342	738,335	1,000,481	27,758	218,305	1,171,819	104,494	549,985	563,712	60,722	1,086,519	1,025,434	243,723
2	Units	Customer	Average		517,740	70,266	12,466	90	4,681	3,686	2,121	73	231	593	56	97	60	2	29	7	4,803
3	Units	Customer	Annual		517,740	70,266	12,466	90	4,681	3,686	2,121	73	231	593	56	97	60	2	29	7	7,894
4																					
5																					
6	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.02072	$0.02072	$0.02072	$0.02072	$0.02072	$0.02072	$0.02072	$0.02072	$0.02072	$0.02072	$0.02072	$0.02072	$0.02072	$0.02072	$0.02072	$0.02072	$0.02072
7	$/Unit	Customer	Dist-Service Drop ($/Customer)		$77.37	$100.00	$204.93	$0.00	$208.98	$216.56	$423.48	$0.00	$425.86	$817.80	$0.00	$2,803.50	$0.00	$2,803.50	$0.00	$0.00	$0.00
8	$/Unit	Customer	Meters ($/Customer)		$24.63	$26.15	$31.77	$1,562.31	$34.89	$37.17	$199.09	$1,562.31	$200.01	$199.99	$1,562.31	$248.70	$1,562.31	$248.70	$1,562.31	$22,941.49	$37.54
9	$/Unit	Customer	Meter Reading ($/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
10	$/Unit	Customer	Billing & Collections ($/Customer)		$28.14	$27.86	$27.86	$27.86	$30.57	$30.57	$30.57	$30.57	$30.57	$30.57	$30.57	$139.32	$139.32	$139.32	$139.32	$139.32	$22.08
11	$/Unit	Customer	Uncollectables ($/Customer)		$8.52	$2.31	$2.31	$2.31	$25.98	$25.98	$25.98	$25.98	$167.19	$167.19	$167.19	$971.88	$971.88	$971.88	$971.88	$971.88	$20.49
12	$/Unit	Customer	Customer Service / Other ($/Customer)		$8.26	$8.00	$8.00	$8.00	$9.06	$9.06	$9.06	$9.06	$14.77	$14.77	$14.77	$51.70	$51.70	$51.70	$51.70	$51.70	$8.50
13																					
14																					
15	($000)	Energy	Total Energy	$302,211	$125,863	$13,267	$12,448	$46	$9,851	$15,301	$20,733	$575	$4,524	$24,284	$2,165	$11,397	$11,682	$1,258	$22,516	$21,250	$5,051
16	($000)	Customer	Total Customer (Billing)	$97,778	$76,065	$11,546	$3,426	$144	$1,449	$1,177	$1,460	$119	$194	$730	$99	$409	$164	$8	$79	$169	$542
17			Total Revenue @ Full MC ($000)	$399,989	$201,927	$24,813	$15,875	$190	$11,299	$16,478	$22,193	$694	$4,718	$25,013	$2,265	$11,806	$11,845	$1,267	$22,595	$21,419	$5,592

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 @ 7.68%	Present Value of Energy (Mills/kWh)
2021	117.10	9.76	163.31	13.61	3.85	7.48	0.00	1.95	13.24	13.24	0.00	20%	0.00	20.72	1.0000	20.72
2022	120.05	10.00	167.42	13.95	3.95	7.67	0.00	2.47	16.77	16.77	0.00	20%	0.00	24.44	0.9287	22.70
2023	122.90	10.24	171.42	14.29	4.04	7.86	0.00	3.04	20.64	20.64	0.00	20%	0.00	28.50	0.8625	24.58
2024	125.77	10.48	175.43	14.62	4.14	8.04	0.00	3.60	24.44	24.44	0.00	20%	0.00	32.49	0.8010	26.02
2025	128.69	10.72	179.49	14.96	4.23	8.23	0.00	3.97	26.96	26.96	0.00	27%	0.00	35.18	0.7439	26.17
2026	131.62	10.97	183.58	15.30	4.33	8.41	0.00	4.19	28.45	28.45	0.00	27%	0.00	36.86	0.6909	25.47
2027	134.52	11.21	187.62	15.64	4.43	8.60	0.00	4.15	28.18	28.18	0.00	27%	0.00	36.78	0.6416	23.60
2028	137.44	11.45	191.68	15.97	4.52	8.78	0.00	4.09	27.77	27.77	0.00	27%	0.00	36.55	0.5959	21.78
2029	140.44	11.70	195.88	16.32	4.62	8.98	0.00	4.43	30.08	30.08	0.00	27%	0.00	39.06	0.5534	21.61
2030	143.51	11.96	200.13	16.68	4.72	9.17	0.00	5.00	33.95	33.95	0.00	35%	0.00	43.12	0.5139	22.16
2031	146.58	12.22	204.39	17.03	4.82	9.36	0.00	5.32	36.12	36.12	0.00	35%	0.00	45.48	0.4773	21.71
2032	149.66	12.47	208.67	17.39	4.92	9.56	0.00	5.64	38.30	38.30	0.00	35%	0.00	47.85	0.4433	21.21
2033	152.77	12.73	213.01	17.75	5.02	9.75	0.00	5.96	40.47	40.47	0.00	35%	0.00	50.22	0.4117	20.68
2034	155.92	12.99	217.41	18.12	5.12	9.96	0.00	6.27	42.57	42.57	0.00	35%	0.00	52.53	0.3823	20.08
2035	159.11	13.26	221.88	18.49	5.23	10.16	0.00	5.94	40.33	40.33	0.00	45%	0.00	50.50	0.3550	17.93
2036	162.36	13.53	226.39	18.87	5.34	10.37	0.00	5.99	40.67	40.67	0.00	45%	0.00	51.04	0.3297	16.83
2037	165.64	13.80	230.95	19.25	5.44	10.58	0.00	6.34	43.05	43.05	0.00	45%	0.00	53.62	0.3062	16.42
2038	168.95	14.08	235.57	19.63	5.55	10.79	0.00	6.84	46.44	46.44	0.00	45%	0.00	57.23	0.2844	16.28
2039	172.33	14.36	240.27	20.02	5.66	11.00	0.00	7.32	49.70	49.70	0.00	45%	0.00	60.70	0.2641	16.03
2040	175.78	14.65	245.07	20.42	5.77	11.22	0.00	7.55	51.26	51.26	0.00	50%	0.00	62.48	0.2453	15.33

	Mills/kWh
2021 (1 Year)	20.72
2021 - 2025 (5 Year, Short Run)	
Sum of PV Costs @ 7.68%	120.20
Annual Cost of Energy @ 22.15%	26.62
2021 - 2030 (10 Year, Medium Run)	
Sum of PV Costs @ 7.68%	234.81
Annual Cost of Energy @ 12.52%	29.40
2021 - 2040 (20 Year, Long Run)	
Sum of PV Costs @ 7.68%	417.30
Annual Cost of Energy @ 7.86%	32.80

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 @ 7.68%	PV of Capacity $/kW	Capacity Mills/kWh	PV of Capacity Mills/kWh
2021	$117.10	1.0000	117.10	18.96	18.96
2022	$120.05	0.9287	111.49	19.44	18.05
2023	$122.90	0.8625	106.00	19.90	17.16
2024	$125.77	0.8010	100.74	20.36	16.31
2025	$128.69	0.7439	95.73	20.84	15.50
2026	$131.62	0.6909	90.94	21.31	14.72
2027	$134.52	0.6416	86.31	21.78	13.97
2028	$137.44	0.5959	81.90	22.25	13.26
2029	$140.44	0.5534	77.72	22.74	12.58
2030	$143.51	0.5139	73.75	23.24	11.94
2031	$146.58	0.4773	69.96	23.73	11.33
2032	$149.66	0.4433	66.34	24.23	10.74
2033	$152.77	0.4117	62.90	24.74	10.19
2034	$155.92	0.3823	59.61	25.25	9.65
2035	$159.11	0.3550	56.48	25.76	9.14
2036	$162.36	0.3297	53.53	26.29	8.67
2037	$165.64	0.3062	50.72	26.82	8.21
2038	$168.95	0.2844	48.05	27.36	7.78
2039	$172.33	0.2641	45.51	27.90	7.37
2040	$175.78	0.2453	43.12	28.46	6.98

	$/kW	Mills/kWh
2021 (1 Year)	117.10	18.96
2021 - 2025 (5 Year, Short Run)		
Sum of PV Costs @ 7.68%	531.06	85.98
Annual Cost of Capacity @ 22.15%	117.63	19.04
2021 - 2030 (10 Year, Medium Run)		
Sum of PV Costs @ 7.68%	941.68	152.45
Annual Cost of Capacity @ 12.52%	117.90	19.09
2021 - 2040 (20 Year, Long Run)		
Sum of PV Costs @ 7.68%	1,497.90	242.51
Annual Cost of Capacity @ 7.86%	117.73	19.06

Avoided Costs

PacifiCorp
Filed Marginal Generation Costs

	12 Months Ended December			12 Months Ended December		
Calendar Year	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)
2021	117.10	163.31	1.95	117.10	163.31	1.95
2022	120.05	167.42	2.47	120.05	167.42	2.47
2023	122.90	171.42	3.04	122.90	171.42	3.04
2024	125.77	175.43	3.60	125.77	175.43	3.60
2025	128.69	179.49	3.97	128.69	179.49	3.97
2026	131.62	183.58	4.19	131.62	183.58	4.19
2027	134.52	187.62	4.15	134.52	187.62	4.15
2028	137.44	191.68	4.09	137.44	191.68	4.09
2029	140.44	195.88	4.43	140.44	195.88	4.43
2030	143.51	200.13	5.00	143.51	200.13	5.00
2031	146.58	204.39	5.32	146.58	204.39	5.32
2032	149.66	208.67	5.64	149.66	208.67	5.64
2033	152.77	213.01	5.96	152.77	213.01	5.96
2034	155.92	217.41	6.27	155.92	217.41	6.27
2035	159.11	221.88	5.94	159.11	221.88	5.94
2036	162.36	226.39	5.99	162.36	226.39	5.99
2037	165.64	230.95	6.34	165.64	230.95	6.34
2038	168.95	235.57	6.84	168.95	235.57	6.84
2039	172.33	240.27	7.32	172.33	240.27	7.32
2040	175.78	245.07	7.55	175.78	245.07	7.55

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
2021 Dollars

Line	Description	Calculation	Total	Demand Related	Energy Related
1	2020 Forecast Growth Related Investments ($000)		$61,303	$61,043	$260
2	2021 Forecast Growth Related Investments ($000)		$19,435	$16,406	$3,029
3	2022 Forecast Growth Related Investments ($000)		$36,337	$36,337	$0
4	2023 Forecast Growth Related Investments ($000)		$16,575	$16,575	$0
5	2024 Forecast Growth Related Investments ($000)		$2,081	$2,081	$0
6					
7	2020 to 2024 Forecast Growth Related Investments ($000)		$135,731	$132,442	$3,289
8					
9	Capacity Addition MW from 2020-2024		3,204		
10					
11	Marginal Investment ($/KW)	7 / 9	$42.36	$41.33	$1.03
12					
13	Annualized Investment ($/KW)	11 x 6.86%	$2.91	$2.84	$0.07
14	Admin. & General Factor ($/KW)	11 x 0.61%	$0.26	$0.25	$0.01
15	Annual O&M Expenses ($/KW)	11 x 1.275%	$0.54	$0.53	$0.01
16					
17	Annualized Marginal Cost ($/KW)	13 + 14 + 15	$3.71	$3.62	$0.09
18					
19	Marginal Cost of Energy-Related Transmission ($/KWh)	17 / 8760 hrs / 79.03% LF			$0.00001

PacifiCorp
Oregon Marginal Cost Study
2020-2024 Forecasted Transmission
December 2021 Dollars (000s)

Line	Description	Calculation	2020	2021	Forecast 2022	2023	2024
1	Bulk Power Lines (grid)		$388	$4,518	$0	$0	$0
2	Escalation Factor		1.060	1.060	1.060	1.060	1.060
3	Adjusted Bulk Power Lines (grid)	1 x 2	$412	$4,789	$0	$0	$0
4							
5	Growth Related Major Projects (local)		$57,445	$13,817	$34,280	$15,637	$1,963
6	Escalation Factor		1.0600	1.0600	1.0600	1.0600	1.0600
7	Adjusted Growth Related Major Projects (local)	5 x 6	$60,892	$14,646	$36,337	$16,575	$2,081
8							
9	Total Growth Related Investments - Demand	3 x 36.75% + 7	$61,043	$16,406	$36,337	$16,575	$2,081
10	Total Growth Related Investments - Energy	3 x 63.25%	$260	$3,029	$0	$0	$0
11	Total Marginal Transmission Investment	3 + 7	$61,303	$19,435	$36,337	$16,575	$2,081

Footnotes:

Line 1 & 5 Bulk power line & growth related projects data provided in 2018 dollars for each year

Line 9 Demand Portion of Transmission = PV of Long Run Capacity Costs / PV of Total Long Run Costs = 242.51 / (242.51+417.30) = 36.75%

Line 10 Energy Portion of Transmission = PV of Long Run Energy Costs / PV of Total Long Run Costs = 417.30 / (242.51+417.30) = 63.25%

Index		Escalation Factor
2018	2021	2018 - 2021
1.0000	1.0600	1.0600

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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
1	Transmission O&M Exp.		172,875	195,628	204,716	206,484	198,670	211,984	215,664	203,261	204,806	206,506	
2	Wheeling		117,161	136,855	138,235	142,125	137,182	151,336	148,425	130,789	134,473	135,022	
3	Net Transmission O&M	1-2	55,713	58,774	66,481	64,359	61,488	60,648	67,239	72,472	70,333	71,484	
4	Transmission Plant		3,342,914	4,339,114	4,500,418	4,724,914	5,231,106	5,387,871	5,910,756	6,051,720	6,222,286	6,353,045	
5	Tran. O&M Loading	3/4	1.667%	1.355%	1.477%	1.362%	1.175%	1.126%	1.138%	1.198%	1.130%	1.125%	1.275%

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		MW
	(A)	(B)	(C)	(D) (B)-(C)	(E)
1	January	6,115,335	1,026,961	5,088,374	8,164
2	February	5,232,606	690,452	4,542,154	8,436
3	March	5,390,036	618,316	4,771,720	7,872
4	April	4,950,593	570,863	4,379,730	7,446
5	May	5,076,782	526,093	4,550,689	7,727
6	June	5,548,195	555,267	4,992,928	9,584
7	July	6,370,540	458,754	5,911,786	10,551
8	August	6,055,886	534,799	5,521,087	10,263
9	September	5,488,846	718,263	4,770,583	8,866
10	October	5,450,455	901,565	4,548,890	7,250
11	November	5,433,689	754,139	4,679,550	7,852
12	December	5,925,869	645,687	5,280,182	8,318
13		67,038,832	8,001,159	59,037,673	
14					
15				Average Monthly MW	8,527
16				Load Factor	79.03%

Source: FERC Form 1, December 31, 2018
Page 401b

DistSub1

PacifiCorp
Oregon Marginal Cost Study
Distribution Substation Costs / kW
2021 Dollars

Line	Description	Calculation	Value
1	Incremental Substation Cost ($/kVA)		$305.11
2	Power Factor		0.95
3	Substation Utilization Factor		49.03%
4	Incremental Substation Cost ($/kW)	1/2*3	$157.47
5			
6	Annual Distribution Carrying Charge		7.58%
7			
8	Substation Marginal Cost ($/kW)	4*6	$11.94

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)
2020	Glendale	OR	12.5	$2,800	$224.00
2022	China Hat	OR	25.0	$3,950	$158.00
2023	Gateway	OR	25.0	$8,350	$334.00
2020	Myrtle Creek	OR	3.0	$900	$300.00
2022	Mill City	OR	25.0	$3,863	$154.52
2023	Wake Robin Ave	OR	30.0	$8,725	$290.83
2022	Conser Road	OR	30.0	$8,809	$293.63
2022	Jefferson	OR	7.5	$759	$101.20
2021	Flint	WA	30.0	$20,022	$667.40
2022	Tieton	WA	25.0	$3,050	$122.00
2024	Dorris	OR	4.6	$1,406	$305.65
		Western States Total	217.6	$62,634	$287.84

2018 Incremental Substation Cost ($/KVA) $287.84

Index		Escalation Factor
2018	2021	2018 - 2021
1.0000	1.0600	1.0600

2021 Incremental Substation Cost ($/KVA) $305.11

PC 1

PacifiCorp
Oregon Marginal Cost Study
Hypothetical Circuit Study Results
Annual Demand and Commitment Costs
December 2021 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line	Load Class		Demand				Commitment			
			Investment $ / kW[1]		Annual $ / kW[1]		Investment $ / Customer		Annual $ / Customer	
			Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor
					(A) x 7.58%	(B) x 7.58%			(E) x 7.58%	(F) x 7.58%
1	Res - Schedule 4	(sec)	$145.82	$260.58	$11.05	$19.75	$717.03	$383.50	$54.35	$29.07
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	$237.40	$361.94	$17.99	$27.44	$1,229.67	$657.68	$93.21	$49.85
5	15+ kW	(sec)	$237.40	$361.94	$17.99	$27.44	$1,229.67	$657.68	$93.21	$49.85
6	Primary	(pri)	$237.40	$361.94	$17.99	$27.44	$1,229.67	$657.68	$93.21	$49.85
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	$142.03	$254.66	$10.77	$19.30	$699.06	$373.89	$52.99	$28.34
10	51-100 kW	(sec)	$142.03	$254.66	$10.77	$19.30	$699.06	$373.89	$52.99	$28.34
11	100 + kW	(sec)	$142.03	$254.66	$10.77	$19.30	$699.06	$373.89	$52.99	$28.34
12	Primary	(pri)	$142.03	$254.66	$10.77	$19.30	$699.06	$373.89	$52.99	$28.34
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	$112.82	$220.55	$8.55	$16.72	$538.95	$288.25	$40.85	$21.85
16	300+ kW	(sec)	$112.82	$220.55	$8.55	$16.72	$538.95	$288.25	$40.85	$21.85
17	Primary	(pri)	$112.82	$220.55	$8.55	$16.72	$538.95	$288.25	$40.85	$21.85
18										
19	LPS - Schedule 48									
20	1 - 4 MW	(sec)	$287.19	$409.49	$21.77	$31.04	$1,522.86	$814.49	$115.43	$61.74
21	1 - 4 MW	(pri)	$287.19	$409.49	$21.77	$31.04	$1,522.86	$814.49	$115.43	$61.74
22	> 4 MW	(sec)	$9.89	$21.31	$0.75	$1.62	$0.00	$0.00	$0.00	$0.00
23	> 4 MW	(pri)	$7.67	$16.54	$0.58	$1.25	$0.00	$0.00	$0.00	$0.00
24										
25	Irrigation - Schedule 41	(sec)	$441.27	$604.64	$33.45	$45.83	$2,338.25	$1,250.59	$177.24	$94.79

Footnote:
[1] $ / kW are in terms of Distribution kW.

PC 2

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors
Poles and Conductor
Three Phase Costs as Demand

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line	Load Class		Demand		Commitment		2021 Demand		2021 Commitment	
			Poles	Conductor	Poles	Conductor	Poles (D) x 1.0392	Conductor (C) x 1.0392	Poles (B) x 1.0392	Conductor (A) x 1.0392
1	Res - Schedule 4	(sec)	$140.32	$250.75	$689.98	$369.03	$145.82	$260.58	$717.03	$383.50
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	$228.44	$348.28	$1,183.28	$632.87	$237.40	$361.94	$1,229.67	$657.68
5	15+ kW	(sec)	$228.44	$348.28	$1,183.28	$632.87	$237.40	$361.94	$1,229.67	$657.68
6	Primary	(pri)	$228.44	$348.28	$1,183.28	$632.87	$237.40	$361.94	$1,229.67	$657.68
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	$136.67	$245.05	$672.69	$359.78	$142.03	$254.66	$699.06	$373.89
10	51-100 kW	(sec)	$136.67	$245.05	$672.69	$359.78	$142.03	$254.66	$699.06	$373.89
11	100 + kW	(sec)	$136.67	$245.05	$672.69	$359.78	$142.03	$254.66	$699.06	$373.89
12	Primary	(pri)	$136.67	$245.05	$672.69	$359.78	$142.03	$254.66	$699.06	$373.89
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	$108.56	$212.23	$518.62	$277.38	$112.82	$220.55	$538.95	$288.25
16	300+ kW	(sec)	$108.56	$212.23	$518.62	$277.38	$112.82	$220.55	$538.95	$288.25
17	Primary	(pri)	$108.56	$212.23	$518.62	$277.38	$112.82	$220.55	$538.95	$288.25
18										
19	LPS - Schedule 48									
20	1 - 4 MW	(sec)	$276.36	$394.04	$1,465.42	$783.76	$287.19	$409.49	$1,522.86	$814.49
21	1 - 4 MW	(pri)	$276.36	$394.04	$1,465.42	$783.76	$287.19	$409.49	$1,522.86	$814.49
22	> 4 MW	(sec)	$9.51	$20.50	$0.00	$0.00	$9.89	$21.31	$0.00	$0.00
23	> 4 MW	(pri)	$7.38	$15.92	$0.00	$0.00	$7.67	$16.54	$0.00	$0.00
24										
25	Irrigation - Schedule 41	(sec)	$424.62	$581.83	$2,250.05	$1,203.42	$441.27	$604.64	$2,338.25	$1,250.59

Index		Escalation Factor
2019	2021	2019 - 2021
1.0200	1.0600	1.0392

Footnote:
Pole and conductor costs from Distribution Circuit Model.

PC 3

PacifiCorp
Oregon Marginal Cost Study
Circuit Distribution Model
Inputs & Calculations

Line	Class	(A)	(B)	(C)	(D)	(E)	(F)
1			Number	Average	Distribution	Average	Percent
2		Annual	of	MWh per	Peak	kW per	Single
3		MWh	Customers	Customer	MW	customer	Phase
4	Class			(A) / (B)		(D)/(B) * 1,000	
5	Res - Schedule 4 (sec)	5,483,041	504,987	10.86	1,122	2.22	100.00%
6	GS - Schedule 23 - 0-15 kW (sec)	616,735	70,353	8.77	91	1.29	81.92%
7	GS - Schedule 23 - 15+ kW (sec)	578,666	12,481	46.36	94	7.54	47.08%
8	GS - Schedule 23 - Primary (pri)	2,207	90	24.44	0	0.91	-
9	GS - Schedule 28 - 0-50 kW (sec)	443,392	4,555	97.34	70	15.41	27.68%
10	GS - Schedule 28 - 51-100 kW (sec)	688,708	3,587	192.00	114	31.78	13.61%
11	GS - Schedule 28 - 100 + kW (sec)	933,234	2,064	452.15	162	78.25	2.02%
12	GS - Schedule 28 - Primary (pri)	26,483	71	373.00	4	61.87	-
13	GS - Schedule 30 - 0-300 kW (sec)	198,747	225	883.32	34	150.79	-
14	GS - Schedule 30 - 300+ kW (sec)	1,066,839	579	1,842.55	165	284.86	0.13%
15	GS - Schedule 30 - Primary (pri)	97,554	55	1,773.71	16	297.32	-
16	Irrigation - Sch 41	200,232	6,626	30.22	33	4.95	14.40%
17	LPS - Schedule 48 - 1 - 4 MW (sec)	518,871	96	5,392.27	77	798.31	-
18	LPS - Schedule 48 - 1 - 4 MW (pri)	540,547	60	8,940.83	79	1,298.82	-
19	LPS - Schedule 48 - > 4 MW (sec)	57,287	2	28,643.60	7	3,599.23	-
20	LPS - Schedule 48 - > 4 MW (pri)	1,041,870	29	36,446.73	133	4,636.55	-
21	Total	12,494,413	605,861		2,200		
22							
23							

Line	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
24			Customer Distribution on the Hypothetical Circuit Branch						
25		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
26					Hypothetical Circuit Branch				Branch
27	Class	1	2	3	4	5	6	7	Total
28	Res - Schedule 4 (sec)	0.33%	0.33%	0.33%	1.79%	1.79%	1.79%	93.66%	100.00%
29	GS - Schedule 23 - 0-15 kW (sec)	0.76%	0.76%	0.76%	2.59%	2.59%	2.59%	89.97%	100.00%
30	GS - Schedule 23 - 15+ kW (sec)	0.76%	0.76%	0.76%	2.59%	2.59%	2.59%	89.97%	100.00%
31	GS - Schedule 23 - Primary (pri)	0.76%	0.76%	0.76%	2.59%	2.59%	2.59%	89.97%	100.00%
32	GS - Schedule 28 - 0-50 kW (sec)	0.38%	0.38%	0.38%	1.40%	1.40%	1.40%	94.65%	100.00%
33	GS - Schedule 28 - 51-100 kW (sec)	0.38%	0.38%	0.38%	1.40%	1.40%	1.40%	94.65%	100.00%
34	GS - Schedule 28 - 100 + kW (sec)	0.38%	0.38%	0.38%	1.40%	1.40%	1.40%	94.65%	100.00%
35	GS - Schedule 28 - Primary (pri)	0.38%	0.38%	0.38%	1.40%	1.40%	1.40%	94.65%	100.00%
36	GS - Schedule 30 - 0-300 kW (sec)	0.32%	0.32%	0.32%	0.78%	0.78%	0.78%	96.69%	100.00%
37	GS - Schedule 30 - 300+ kW (sec)	0.32%	0.32%	0.32%	0.78%	0.78%	0.78%	96.69%	100.00%
38	GS - Schedule 30 - Primary (pri)	0.32%	0.32%	0.32%	0.78%	0.78%	0.78%	96.69%	100.00%
39	Irrigation - Sch 41	0.98%	0.98%	0.98%	7.86%	7.86%	7.86%	73.47%	100.00%
40	LPS - Schedule 48 - 1 - 4 MW (sec)	1.31%	1.31%	1.31%	1.48%	1.48%	1.48%	91.63%	100.00%
41	LPS - Schedule 48 - 1 - 4 MW (pri)	1.31%	1.31%	1.31%	1.48%	1.48%	1.48%	91.63%	100.00%
42	LPS - Schedule 48 - > 4 MW (sec)			Large Customers are on dedicated circuits and are not included here					
43	LPS - Schedule 48 - > 4 MW (pri)			Large Customers are on dedicated circuits and are not included here					
44									
45									

Line	Item	Value
46	System property records & engineering information	
47	Number of pole feet in Oregon	75,328,924
48	Number of pole miles in Oregon	14,267
49	Number of trench feet in Oregon	28,218,782
50	Number of trench miles in Oregon	5,344
51	Total miles in Oregon	19,611
52	Number of circuits in Oregon	531
53	Number of poles in Oregon	372,724
54	Poles per mile	26.13
55	Customers per mile	30.89
56	MWh per customer	20.62
57	MWh per circuit	23,530
58	Branches per circuit	7
59	Miles per circuit	36.93
60	Miles per branch	5.28
61	Single Phase Miles per Branch[1]	1.85

[1]A 12 KV circuit 12 miles long has approx. 3 miles of single phase, which is approx. 25 percent of circuit distance, so applying 25% to the Miles per Circuit and dividing this amount by the 5 outer branches gives the Single Phase Miles per Branch.

PC 4

PacifiCorp
Oregon Circuit Model Study
Customer Distribution on the Hypothetical Circuit Branch

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
					Hypothetical Circuit Branch				Branch
Line	Class	1	2	3	4	5	6	7	Total
1	Res - Schedule 4 (sec)	0.33%	0.33%	0.33%	1.79%	1.79%	1.79%	93.66%	100.00%
2	GS - Schedule 23 - 0-15 kW (sec)	0.76%	0.76%	0.76%	2.59%	2.59%	2.59%	89.97%	100.00%
3	GS - Schedule 23 - 15+ kW (sec)	0.76%	0.76%	0.76%	2.59%	2.59%	2.59%	89.97%	100.00%
4	GS - Schedule 23 - Primary (pri)	0.76%	0.76%	0.76%	2.59%	2.59%	2.59%	89.97%	100.00%
5	GS - Schedule 28 - 0-50 kW (sec)	0.38%	0.38%	0.38%	1.40%	1.40%	1.40%	94.65%	100.00%
6	GS - Schedule 28 - 51-100 kW (sec)	0.38%	0.38%	0.38%	1.40%	1.40%	1.40%	94.65%	100.00%
7	GS - Schedule 28 - 100 + kW (sec)	0.38%	0.38%	0.38%	1.40%	1.40%	1.40%	94.65%	100.00%
8	GS - Schedule 28 - Primary (pri)	0.38%	0.38%	0.38%	1.40%	1.40%	1.40%	94.65%	100.00%
9	GS - Schedule 30 - 0-300 kW (sec)	0.32%	0.32%	0.32%	0.78%	0.78%	0.78%	96.69%	100.00%
10	GS - Schedule 30 - 300+ kW (sec)	0.32%	0.32%	0.32%	0.78%	0.78%	0.78%	96.69%	100.00%
11	GS - Schedule 30 - Primary (pri)	0.32%	0.32%	0.32%	0.78%	0.78%	0.78%	96.69%	100.00%
12	Irrigation - Sch 41	0.98%	0.98%	0.98%	7.86%	7.86%	7.86%	73.47%	100.00%
13	LPS - Schedule 48 - 1 - 4 MW (sec)	1.31%	1.31%	1.31%	1.48%	1.48%	1.48%	91.63%	100.00%
14	LPS - Schedule 48 - 1 - 4 MW (pri)	1.31%	1.31%	1.31%	1.48%	1.48%	1.48%	91.63%	100.00%
15	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
16	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-

Except where customers own their own transformers.

PC 5

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)	3.11	3.11	3.11	16.98	16.98	16.98	890.73	951.01
4	GS - Schedule 23 - 0-15 kW (sec)	1.00	1.00	1.00	3.43	3.43	3.43	119.20	132.49
5	GS - Schedule 23 - 15+ kW (sec)	0.18	0.18	0.18	0.61	0.61	0.61	21.15	23.50
6	GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.17
7	GS - Schedule 28 - 0-50 kW (sec)	0.03	0.03	0.03	0.12	0.12	0.12	8.12	8.58
8	GS - Schedule 28 - 51-100 kW (sec)	0.03	0.03	0.03	0.09	0.09	0.09	6.39	6.76
9	GS - Schedule 28 - 100 + kW (sec)	0.01	0.01	0.01	0.05	0.05	0.05	3.68	3.89
10	GS - Schedule 28 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.13
11	GS - Schedule 30 - 0-300 kW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.41	0.42
12	GS - Schedule 30 - 300+ kW (sec)	0.00	0.00	0.00	0.01	0.01	0.01	1.05	1.09
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	0.12	0.12	0.12	0.98	0.98	0.98	9.17	12.48
15	LPS - Schedule 48 - 1 - 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.18
16	LPS - Schedule 48 - 1 - 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.11
17	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
18	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
19	Total	4.50	4.50	4.50	22.29	22.29	22.29	1,060.55	1,140.92
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 3.11 is 504,987 Residential Customers X .327% customers on Branch 1 divided by 531 circuits.								
25									
26	Percent of Customers								
27	Res - Schedule 4 (sec)	69.15%	69.15%	69.15%	76.18%	76.18%	76.18%	83.99%	83.35%
28	GS - Schedule 23 - 0-15 kW (sec)	22.29%	22.29%	22.29%	15.38%	15.38%	15.38%	11.24%	11.61%
29	GS - Schedule 23 - 15+ kW (sec)	3.95%	3.95%	3.95%	2.73%	2.73%	2.73%	1.99%	2.06%
30	GS - Schedule 23 - Primary (pri)	0.03%	0.03%	0.03%	0.02%	0.02%	0.02%	0.01%	0.01%
31	GS - Schedule 28 - 0-50 kW (sec)	0.73%	0.73%	0.73%	0.54%	0.54%	0.54%	0.77%	0.75%
32	GS - Schedule 28 - 51-100 kW (sec)	0.57%	0.57%	0.57%	0.42%	0.42%	0.42%	0.60%	0.59%
33	GS - Schedule 28 - 100 + kW (sec)	0.33%	0.33%	0.33%	0.24%	0.24%	0.24%	0.35%	0.34%
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)	0.03%	0.03%	0.03%	0.01%	0.01%	0.01%	0.04%	0.04%
36	GS - Schedule 30 - 300+ kW (sec)	0.08%	0.08%	0.08%	0.04%	0.04%	0.04%	0.10%	0.10%
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	2.73%	2.73%	2.73%	4.40%	4.40%	4.40%	0.86%	1.09%
39	LPS - Schedule 48 - 1 - 4 MW (sec)	0.05%	0.05%	0.05%	0.01%	0.01%	0.01%	0.02%	0.02%
40	LPS - Schedule 48 - 1 - 4 MW (pri)	0.03%	0.03%	0.03%	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	4.50	4.50	4.50			22.29		35.79
47	1,2,3,4,5,6,7	4.50	4.50	4.50	22.29	22.29	22.29	1,060.55	1,140.92
48									
49	1,2,3,6	12.6%	12.6%	12.6%			62.3%		100.0%
50	1,2,3,4,5,6,7	0.4%	0.4%	0.4%	2.0%	2.0%	2.0%	93.0%	100.0%

PC 6

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)	6.91	6.91	6.91	37.74	37.74	37.74	1,979.40	2,113.35
4	GS - Schedule 23 - 0-15 kW (sec)	1.29	1.29	1.29	4.42	4.42	4.42	153.65	170.78
5	GS - Schedule 23 - 15+ kW (sec)	1.34	1.34	1.34	4.59	4.59	4.59	159.55	177.34
6	GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.16
7	GS - Schedule 28 - 0-50 kW (sec)	0.51	0.51	0.51	1.85	1.85	1.85	125.11	132.18
8	GS - Schedule 28 - 51-100 kW (sec)	0.82	0.82	0.82	3.01	3.01	3.01	203.21	214.70
9	GS - Schedule 28 - 100 + kW (sec)	1.16	1.16	1.16	4.26	4.26	4.26	287.90	304.17
10	GS - Schedule 28 - Primary (pri)	0.03	0.03	0.03	0.12	0.12	0.12	7.83	8.27
11	GS - Schedule 30 - 0-300 kW (sec)	0.21	0.21	0.21	0.50	0.50	0.50	61.78	63.89
12	GS - Schedule 30 - 300+ kW (sec)	1.00	1.00	1.00	2.43	2.43	2.43	300.33	310.61
13	GS - Schedule 30 - Primary (pri)	0.10	0.10	0.10	0.24	0.24	0.24	29.78	30.80
14	Irrigation - Sch 41	0.61	0.61	0.61	4.85	4.85	4.85	45.37	61.75
15	LPS - Schedule 48 - 1 - 4 MW (sec)	1.90	1.90	1.90	2.14	2.14	2.14	132.55	144.67
16	LPS - Schedule 48 - 1 - 4 MW (pri)	1.94	1.94	1.94	2.19	2.19	2.19	135.50	147.88
17	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
18	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
19	Total	17.83	17.83	17.83	68.33	68.33	68.33	3,622.07	3,880.54
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 6.9 is 3.11 Residential Customers multiplied by 2.22 average Dist. kW per Customer.								
25									
26	Percent of Branch Load								
27	Res - Schedule 4 (sec)	38.78%	38.78%	38.78%	55.23%	55.23%	55.23%	54.65%	54.46%
28	GS - Schedule 23 - 0-15 kW (sec)	7.25%	7.25%	7.25%	6.47%	6.47%	6.47%	4.24%	4.40%
29	GS - Schedule 23 - 15+ kW (sec)	7.53%	7.53%	7.53%	6.71%	6.71%	6.71%	4.40%	4.57%
30	GS - Schedule 23 - Primary (pri)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.00%	0.00%
31	GS - Schedule 28 - 0-50 kW (sec)	2.84%	2.84%	2.84%	2.71%	2.71%	2.71%	3.45%	3.41%
32	GS - Schedule 28 - 51-100 kW (sec)	4.61%	4.61%	4.61%	4.40%	4.40%	4.40%	5.61%	5.53%
33	GS - Schedule 28 - 100 + kW (sec)	6.53%	6.53%	6.53%	6.24%	6.24%	6.24%	7.95%	7.84%
34	GS - Schedule 28 - Primary (pri)	0.18%	0.18%	0.18%	0.17%	0.17%	0.17%	0.22%	0.21%
35	GS - Schedule 30 - 0-300 kW (sec)	1.15%	1.15%	1.15%	0.73%	0.73%	0.73%	1.71%	1.65%
36	GS - Schedule 30 - 300+ kW (sec)	5.61%	5.61%	5.61%	3.55%	3.55%	3.55%	8.29%	8.00%
37	GS - Schedule 30 - Primary (pri)	0.56%	0.56%	0.56%	0.35%	0.35%	0.35%	0.82%	0.79%
38	Irrigation - Sch 41	3.41%	3.41%	3.41%	7.10%	7.10%	7.10%	1.25%	1.59%
39	LPS - Schedule 48 - 1 - 4 MW (sec)	10.66%	10.66%	10.66%	3.13%	3.13%	3.13%	3.66%	3.73%
40	LPS - Schedule 48 - 1 - 4 MW (pri)	10.90%	10.90%	10.90%	3.20%	3.20%	3.20%	3.74%	3.81%
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	17.83	17.83	17.83			68.33		121.81
47	1,2,3,4,5,6,7	17.83	17.83	17.83	68.33	68.33	68.33	3,622.07	3,880.54
48									
49	1,2,3,6	14.64%	14.64%	14.64%			56.09%		100.00%
50	1,2,3,4,5,6,7	0.46%	0.46%	0.46%	1.76%	1.76%	1.76%	93.34%	100.00%

PC 7

PacifiCorp
Oregon Circuit Model Study
System-wide Pole and Conductor Costs

Adjusted Oregon Line Costs per Mile

	State Specific Account 364 Pole Statistics				Adjustment
	Poles	Pole Feet	Pole Miles	Poles / Mile	Factor
California	55,605	12,356,706	2,340	23.76	0.907
Idaho	97,159	22,745,816	4,308	22.55	0.861
Oregon	372,724	75,328,924	14,267	26.13	0.997
Utah	337,400	57,744,612	10,936	30.85	1.177
Washington	99,821	18,927,800	3,585	27.85	1.063
Wyoming	156,902	38,489,046	7,290	21.52	0.821
Total	1,119,611	225,592,904	42,726	26.20	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	$23,990	0.997	$23,917	$12,792	$36,709
3 Phase - 1/0 ACSR	$43,964	0.997	$43,831	$28,864	$72,695
3 Phase - 447 AAC & 4\0 AAC	$49,159	0.997	$49,010	$62,211	$111,221
3 Phase -795 AAC & 477 AAC	$51,257	0.997	$51,102	$110,152	$161,254

	Costs for Branches 1,2,3,4,5		
	1 Phase - 1/0 ACSR	3 Phase - 1/0 ACSR	Total
Poles	$44,167	$150,317	$194,484
Conductors	$23,622	$98,988	$122,611
Total	$67,789	$249,305	$317,094

	Costs for Branch 6	Cost for Branch 7
	3 Phase - 447 AAC & 4\0 AAC	3 Phase -795 AAC & 477 AAC
Poles	$258,584	$269,619
Conductors	$328,232	$581,174
Total	$586,816	$850,794

Miles per Branch	5.28
Single Phase Miles Per Branch	1.85
Three Phase Miles Per Branch	3.43

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	$44,167	$44,167	$0	$23,622	$23,622	$0
3 Phase - 1/0 ACSR	$150,317	$82,024	$68,293	$98,988	$43,870	$55,118
Total Branches 1,2,3,4,5	$194,484	$126,191	$68,293	$122,611	$67,492	$55,118
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$258,584	$126,191	$132,393	$328,232	$67,492	$260,740
Branch 7						
3 Phase -795 AAC & 477 AAC	$269,619	$126,191	$143,428	$581,174	$67,492	$513,682
Total All Branches	$1,500,623	$883,336	$617,286	$1,522,459	$472,444	$1,050,015

Branch pole and conductor commitment costs equals single or three Phase Miles Per Branch Multiplied by 1 Phase - 1/0 ACSR Cost

PC 8

PacifiCorp
Oregon Circuit Model Study
Calculation of Hypothetical Circuit Model Branch Cost

	Conductors Type	(A) Total Cost Poles	(B) Total Cost Conductor	(C) Commitment Cost Poles	(D) Commitment Cost Conductor	(E) Demand Cost Poles	(F) Demand Cost Conductor
Branch 1							
	1 Phase - 1/0 ACSR	$ 44,167	$ 23,622	$ 44,167	$ 23,622		
	3 Phase - 1/0 ACSR	$ 150,317	$ 98,988	$ 82,024	$ 43,870	$ 68,293	$ 55,118
	Total segment	$ 194,484	$ 122,611	$ 126,191	$ 67,492	$ 68,293	$ 55,118
Branch 2							
	1 Phase - 1/0 ACSR	$ 44,167	$ 23,622	$ 44,167	$ 23,622		
	3 Phase - 1/0 ACSR	$ 150,317	$ 98,988	$ 82,024	$ 43,870	$ 68,293	$ 55,118
	Total Segments	$ 194,484	$ 122,611	$ 126,191	$ 67,492	$ 68,293	$ 55,118
Branch 3							
	1 Phase - 1/0 ACSR	$ 44,167	$ 23,622	$ 44,167	$ 23,622		
	3 Phase - 1/0 ACSR	$ 150,317	$ 98,988	$ 82,024	$ 43,870	$ 68,293	$ 55,118
	Total Segments	$ 194,484	$ 122,611	$ 126,191	$ 67,492	$ 68,293	$ 55,118
Branch 4							
	1 Phase - 1/0 ACSR	$ 44,167	$ 23,622	$ 44,167	$ 23,622		
	3 Phase - 1/0 ACSR	$ 150,317	$ 98,988	$ 82,024	$ 43,870	$ 68,293	$ 55,118
	Total Segments	$ 194,484	$ 122,611	$ 126,191	$ 67,492	$ 68,293	$ 55,118
Branch 5							
	1 Phase - 1/0 ACSR	$ 44,167	$ 23,622	$ 44,167	$ 23,622		
	3 Phase - 1/0 ACSR	$ 150,317	$ 98,988	$ 82,024	$ 43,870	$ 68,293	$ 55,118
	Total Segments	$ 194,484	$ 122,611	$ 126,191	$ 67,492	$ 68,293	$ 55,118
Branch 6							
	3 Phase - 447 AAC & 4\0 AAC	$ 258,584	$ 328,232	$ 126,191	$ 67,492	$ 132,393	$ 260,740
	Total Segments	$ 258,584	$ 328,232	$ 126,191	$ 67,492	$ 132,393	$ 260,740
Branch 7							
	3 Phase -795 AAC & 477 AAC	$ 269,619	$ 581,174	$ 126,191	$ 67,492	$ 143,428	$ 513,682
	Total segment	$ 269,619	$ 581,174	$ 126,191	$ 67,492	$ 143,428	$ 513,682
	$3,023,082	$1,500,623	$1,522,459	$883,336	$472,444	$617,286	$1,050,015

Source - 'System-wide Pole and Conductor Costs' (PC 7)

PC 9

PacifiCorp
Oregon Circuit Model Study
Pole Demand Calculations

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Hypothetical Circuit Branch								
		1	2	3	4	5	6	7		
1	% customer	14.64%	14.64%	14.64%			56.09%		100.00%	
2	Branch 6 Cost	$ 19,377	$ 19,377	$ 19,377			$ 74,263		$ 132,393	$ / kW
3	% customer	0.46%	0.46%	0.46%	1.76%	1.76%	1.76%	93.34%	100.00%	
4	Branch 7 Cost	$ 659	$ 659	$ 659	$ 2,525	$ 2,525	$ 2,525	$ 133,875	$ 143,428	
5	Branch Commitment Cost	$ 68,293	$ 68,293	$ 68,293	$ 68,293	$ 68,293				Average
6	Total	$ 88,329	$ 88,329	$ 88,329	$ 70,818	$ 70,818	$ 76,788	$ 133,875	$ 617,286	$ 159.07
7										
8									Total	
9									Demand	$ Per
10	Class Cost per Branch	1	2	3	4	5	6	7	Cost	kW
11	Res - Schedule 4 (sec)	$ 34,251	$ 34,251	$ 34,251	$ 39,113	$ 39,113	$ 42,410	$ 73,160	$ 296,550	$ 140.32
12	GS - Schedule 23 - 0-15 kW (sec)	$ 6,404	$ 6,404	$ 6,404	$ 4,579	$ 4,579	$ 4,965	$ 5,679	$ 39,013	$ 228.44
13	GS - Schedule 23 - 15+ kW (sec)	$ 6,650	$ 6,650	$ 6,650	$ 4,755	$ 4,755	$ 5,156	$ 5,897	$ 40,513	$ 228.44
14	GS - Schedule 23 - Primary (pri)	$ 6	$ 6	$ 6	$ 4	$ 4	$ 5	$ 5	$ 35	$ 228.44
15	GS - Schedule 28 - 0-50 kW (sec)	$ 2,507	$ 2,507	$ 2,507	$ 1,919	$ 1,919	$ 2,081	$ 4,624	$ 18,065	$ 136.67
16	GS - Schedule 28 - 51-100 kW (sec)	$ 4,072	$ 4,072	$ 4,072	$ 3,117	$ 3,117	$ 3,380	$ 7,511	$ 29,342	$ 136.67
17	GS - Schedule 28 - 100 + kW (sec)	$ 5,769	$ 5,769	$ 5,769	$ 4,416	$ 4,416	$ 4,789	$ 10,641	$ 41,571	$ 136.67
18	GS - Schedule 28 - Primary (pri)	$ 157	$ 157	$ 157	$ 120	$ 120	$ 130	$ 289	$ 1,131	$ 136.67
19	GS - Schedule 30 - 0-300 kW (sec)	$ 1,019	$ 1,019	$ 1,019	$ 518	$ 518	$ 561	$ 2,283	$ 6,936	$ 108.56
20	GS - Schedule 30 - 300+ kW (sec)	$ 4,953	$ 4,953	$ 4,953	$ 2,516	$ 2,516	$ 2,728	$ 11,100	$ 33,720	$ 108.56
21	GS - Schedule 30 - Primary (pri)	$ 491	$ 491	$ 491	$ 249	$ 249	$ 271	$ 1,101	$ 3,343	$ 108.56
22	Irrigation - Sch 41	$ 3,009	$ 3,009	$ 3,009	$ 5,031	$ 5,031	$ 5,455	$ 1,677	$ 26,220	$ 424.62
23	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 9,415	$ 9,415	$ 9,415	$ 2,216	$ 2,216	$ 2,403	$ 4,899	$ 39,980	$ 276.36
24	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 9,625	$ 9,625	$ 9,625	$ 2,265	$ 2,265	$ 2,456	$ 5,008	$ 40,868	$ 276.36
25	LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 88,329	$ 88,329	$ 88,329	$ 70,818	$ 70,818	$ 76,788	$ 133,875	$ 617,286	

Sources: Line 1 & 3 - 'Circuit kW Load by Branch' (PC 6)
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) for $132,393
Line 1 X $132,393
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) for $143,428
Line 3 X $143,428
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	14.64%	14.64%	14.64%			56.09%		100.00%	
2	Branch 6 Cost	$ 38,161	$ 38,161	$ 38,161			$ 146,257		$ 260,740	$ / kW
3	% customer	0.46%	0.46%	0.46%	1.76%	1.76%	1.76%	93.34%	100.00%	
4	Branch 7 Cost	$ 2,360	$ 2,360	$ 2,360	$ 9,045	$ 9,045	$ 9,045	$ 479,468	$ 513,682	
5	Branch Commitment Cost	$ 55,118	$ 55,118	$ 55,118	$ 55,118	$ 55,118				Average
6	Total	$ 95,640	$ 95,640	$ 95,640	$ 64,163	$ 64,163	$ 155,302	$ 479,468	$ 1,050,015	$ 270.58
7										
8									Total	
9									Demand	$ Per
10	Class Cost per Branch	1	2	3	4	5	6	7	Cost	kW
11	Res - Schedule 4 (sec)	$ 37,086	$ 37,086	$ 37,086	$ 35,437	$ 35,437	$ 85,773	$ 262,021	$ 529,926	$ 250.75
12	GS - Schedule 23 - 0-15 kW (sec)	$ 6,934	$ 6,934	$ 6,934	$ 4,149	$ 4,149	$ 10,041	$ 20,339	$ 59,479	$ 348.28
13	GS - Schedule 23 - 15+ kW (sec)	$ 7,200	$ 7,200	$ 7,200	$ 4,308	$ 4,308	$ 10,427	$ 21,121	$ 61,765	$ 348.28
14	GS - Schedule 23 - Primary (pri)	$ 6	$ 6	$ 6	$ 4	$ 4	$ 9	$ 19	$ 54	$ 348.28
15	GS - Schedule 28 - 0-50 kW (sec)	$ 2,715	$ 2,715	$ 2,715	$ 1,739	$ 1,739	$ 4,209	$ 16,561	$ 32,391	$ 245.05
16	GS - Schedule 28 - 51-100 kW (sec)	$ 4,409	$ 4,409	$ 4,409	$ 2,824	$ 2,824	$ 6,836	$ 26,899	$ 52,612	$ 245.05
17	GS - Schedule 28 - 100 + kW (sec)	$ 6,247	$ 6,247	$ 6,247	$ 4,001	$ 4,001	$ 9,685	$ 38,110	$ 74,538	$ 245.05
18	GS - Schedule 28 - Primary (pri)	$ 170	$ 170	$ 170	$ 109	$ 109	$ 263	$ 1,036	$ 2,027	$ 245.05
19	GS - Schedule 30 - 0-300 kW (sec)	$ 1,103	$ 1,103	$ 1,103	$ 469	$ 469	$ 1,135	$ 8,178	$ 13,560	$ 212.23
20	GS - Schedule 30 - 300+ kW (sec)	$ 5,363	$ 5,363	$ 5,363	$ 2,280	$ 2,280	$ 5,518	$ 39,755	$ 65,921	$ 212.23
21	GS - Schedule 30 - Primary (pri)	$ 532	$ 532	$ 532	$ 226	$ 226	$ 547	$ 3,942	$ 6,536	$ 212.23
22	Irrigation - Sch 41	$ 3,258	$ 3,258	$ 3,258	$ 4,558	$ 4,558	$ 11,032	$ 6,005	$ 35,927	$ 581.83
23	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 10,195	$ 10,195	$ 10,195	$ 2,008	$ 2,008	$ 4,859	$ 17,546	$ 57,005	$ 394.04
24	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 10,421	$ 10,421	$ 10,421	$ 2,052	$ 2,052	$ 4,967	$ 17,936	$ 58,272	$ 394.04
25	LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 95,640	$ 95,640	$ 95,640	$ 64,163	$ 64,163	$ 155,302	$ 479,468	$ 1,050,015	

PC 11

PacifiCorp
Oregon Circuit Model Study
Pole Commitment Calculations

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
					Hypothetical Circuit Branch					
		1	2	3	4	5	6	7		
1	% customer	12.57%	12.57%	12.57%			62.29%		100.00%	
2	Branch 6 Cost	$ -	$ -	$ -			$ -		$ -	$ Per
3	% customer	0.39%	0.39%	0.39%	1.95%	1.95%	1.95%	92.96%	100.00%	Customer
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 126,191	$ 126,191	$ 126,191	$ 126,191	$ 126,191	$ 126,191	$ 126,191		Average
6	Total	$ 126,191	$ 126,191	$ 126,191	$ 126,191	$ 126,191	$ 126,191	$ 126,191	$ 883,336	$ 774.23
7										
8									Total	
9									Commitment	$ Per
10	Class Cost per Branch	1	2	3	4	5	6	7	Cost	Customer
11	Res - Schedule 4 (sec)	$ 87,261	$ 87,261	$ 87,261	$ 96,137	$ 96,137	$ 96,137	$ 105,985	$ 656,179	$ 689.98
12	GS - Schedule 23 - 0-15 kW (sec)	$ 28,128	$ 28,128	$ 28,128	$ 19,403	$ 19,403	$ 19,403	$ 14,183	$ 156,775	$ 1,183.28
13	GS - Schedule 23 - 15+ kW (sec)	$ 4,990	$ 4,990	$ 4,990	$ 3,442	$ 3,442	$ 3,442	$ 2,516	$ 27,813	$ 1,183.28
14	GS - Schedule 23 - Primary (pri)	$ 36	$ 36	$ 36	$ 25	$ 25	$ 25	$ 18	$ 201	$ 1,183.28
15	GS - Schedule 28 - 0-50 kW (sec)	$ 921	$ 921	$ 921	$ 680	$ 680	$ 680	$ 966	$ 5,770	$ 672.69
16	GS - Schedule 28 - 51-100 kW (sec)	$ 725	$ 725	$ 725	$ 536	$ 536	$ 536	$ 761	$ 4,544	$ 672.69
17	GS - Schedule 28 - 100 + kW (sec)	$ 417	$ 417	$ 417	$ 308	$ 308	$ 308	$ 438	$ 2,615	$ 672.69
18	GS - Schedule 28 - Primary (pri)	$ 14	$ 14	$ 14	$ 11	$ 11	$ 11	$ 15	$ 90	$ 672.69
19	GS - Schedule 30 - 0-300 kW (sec)	$ 38	$ 38	$ 38	$ 19	$ 19	$ 19	$ 49	$ 220	$ 518.62
20	GS - Schedule 30 - 300+ kW (sec)	$ 98	$ 98	$ 98	$ 48	$ 48	$ 48	$ 125	$ 565	$ 518.62
21	GS - Schedule 30 - Primary (pri)	$ 9	$ 9	$ 9	$ 5	$ 5	$ 5	$ 12	$ 54	$ 518.62
22	Irrigation - Sch 41	$ 3,443	$ 3,443	$ 3,443	$ 5,553	$ 5,553	$ 5,553	$ 1,091	$ 28,078	$ 2,250.05
23	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 67	$ 67	$ 67	$ 15	$ 15	$ 15	$ 20	$ 266	$ 1,465.42
24	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 42	$ 42	$ 42	$ 10	$ 10	$ 10	$ 12	$ 167	$ 1,465.42
25	LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 126,191	$ 126,191	$ 126,191	$ 126,191	$ 126,191	$ 126,191	$ 126,191	$ 883,336	

PacifiCorp
Oregon Circuit Model Study
Conductor Commitment Calculations

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
					Hypothetical Circuit Branch					
Line		1	2	3	4	5	6	7		
1	% customer	12.57%	12.57%	12.57%			62.29%		100.00%	
2	Branch 6 Cost	$ -	$ -	$ -			$ -		$ -	$ Per
3	% customer	0.39%	0.39%	0.39%	1.95%	1.95%	1.95%	92.96%	100.00%	Customer
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 67,492	$ 67,492	$ 67,492	$ 67,492	$ 67,492	$ 67,492	$ 67,492		Average
6	Total	$ 67,492	$ 67,492	$ 67,492	$ 67,492	$ 67,492	$ 67,492	$ 67,492	$ 472,444	$ 414.09
7										
8									Total	
9									Commitment	$ Per
10	Class Cost per Branch	1	2	3	4	5	6	7	Cost	Customer
11	Res - Schedule 4 (sec)	$ 46,671	$ 46,671	$ 46,671	$ 51,418	$ 51,418	$ 51,418	$ 56,685	$ 350,951	$ 369.03
12	GS - Schedule 23 - 0-15 kW (sec)	$ 15,044	$ 15,044	$ 15,044	$ 10,377	$ 10,377	$ 10,377	$ 7,586	$ 83,850	$ 632.87
13	GS - Schedule 23 - 15+ kW (sec)	$ 2,669	$ 2,669	$ 2,669	$ 1,841	$ 1,841	$ 1,841	$ 1,346	$ 14,875	$ 632.87
14	GS - Schedule 23 - Primary (pri)	$ 19	$ 19	$ 19	$ 13	$ 13	$ 13	$ 10	$ 108	$ 632.87
15	GS - Schedule 28 - 0-50 kW (sec)	$ 493	$ 493	$ 493	$ 364	$ 364	$ 364	$ 517	$ 3,086	$ 359.78
16	GS - Schedule 28 - 51-100 kW (sec)	$ 388	$ 388	$ 388	$ 287	$ 287	$ 287	$ 407	$ 2,430	$ 359.78
17	GS - Schedule 28 - 100 + kW (sec)	$ 223	$ 223	$ 223	$ 165	$ 165	$ 165	$ 234	$ 1,398	$ 359.78
18	GS - Schedule 28 - Primary (pri)	$ 8	$ 8	$ 8	$ 6	$ 6	$ 6	$ 8	$ 48	$ 359.78
19	GS - Schedule 30 - 0-300 kW (sec)	$ 20	$ 20	$ 20	$ 10	$ 10	$ 10	$ 26	$ 118	$ 277.38
20	GS - Schedule 30 - 300+ kW (sec)	$ 53	$ 53	$ 53	$ 26	$ 26	$ 26	$ 67	$ 302	$ 277.38
21	GS - Schedule 30 - Primary (pri)	$ 5	$ 5	$ 5	$ 2	$ 2	$ 2	$ 6	$ 29	$ 277.38
22	Irrigation - Sch 41	$ 1,841	$ 1,841	$ 1,841	$ 2,970	$ 2,970	$ 2,970	$ 583	$ 15,017	$ 1,203.42
23	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 36	$ 36	$ 36	$ 8	$ 8	$ 8	$ 11	$ 142	$ 783.76
24	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 22	$ 22	$ 22	$ 5	$ 5	$ 5	$ 7	$ 89	$ 783.76
25	LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 67,492	$ 67,492	$ 67,492	$ 67,492	$ 67,492	$ 67,492	$ 67,492	$ 472,444	

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	$ 51,102	$ 110,152	$ 51,102	$ 110,152
2 Average Trunk Length	0.67	miles	0.67	miles
3 Total Construction Cost	$ 34,238	$ 73,802	$ 34,238	$ 73,802
4 Customer Peak Demand	4,637	kW	3,599	kW
5 Demand Cost $/kW	$7.38	$15.92	$9.51	$20.50

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

		(A)	(B)	(C)	(D)	(E)	(F)	(G) =(C)*(F)	(H) =(D)*(F)
		Commitment $/Customer		Demand $/Dist. kW		Typical circuit		Demand $/circuit	
Line	Class	Poles	Conductor	Poles	Conductor	Customers	kW	Poles	Conductor
1	Res - Schedule 4 (sec)	$ 689.98	$ 369.03	$ 140.32	$ 250.75	951.0	2,113.35	$ 296,550	$ 529,926
2	GS - Schedule 23 - 0-15 kW (sec)	$ 1,183.28	$ 632.87	$ 228.44	$ 348.28	132.5	170.78	$ 39,013	$ 59,479
3	GS - Schedule 23 - 15+ kW (sec)	$ 1,183.28	$ 632.87	$ 228.44	$ 348.28	23.5	177.34	$ 40,513	$ 61,765
4	GS - Schedule 23 - Primary (pri)	$ 1,183.28	$ 632.87	$ 228.44	$ 348.28	0.2	0.16	$ 35	$ 54
5	GS - Schedule 28 - 0-50 kW (sec)	$ 672.69	$ 359.78	$ 136.67	$ 245.05	8.6	132.18	$ 18,065	$ 32,391
6	GS - Schedule 28 - 51-100 kW (sec)	$ 672.69	$ 359.78	$ 136.67	$ 245.05	6.8	214.70	$ 29,342	$ 52,612
7	GS - Schedule 28 - 100 + kW (sec)	$ 672.69	$ 359.78	$ 136.67	$ 245.05	3.9	304.17	$ 41,571	$ 74,538
8	GS - Schedule 28 - Primary (pri)	$ 672.69	$ 359.78	$ 136.67	$ 245.05	0.1	8.27	$ 1,131	$ 2,027
9	GS - Schedule 30 - 0-300 kW (sec)	$ 518.62	$ 277.38	$ 108.56	$ 212.23	0.4	63.89	$ 6,936	$ 13,560
10	GS - Schedule 30 - 300+ kW (sec)	$ 518.62	$ 277.38	$ 108.56	$ 212.23	1.1	310.61	$ 33,720	$ 65,921
11	GS - Schedule 30 - Primary (pri)	$ 518.62	$ 277.38	$ 108.56	$ 212.23	0.1	30.80	$ 3,343	$ 6,536
12	Irrigation - Sch 41	$ 2,250.05	$ 1,203.42	$ 424.62	$ 581.83	12.5	61.75	$ 26,220	$ 35,927
13	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 1,465.42	$ 783.76	$ 276.36	$ 394.04	0.2	144.67	$ 39,980	$ 57,005
14	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 1,465.42	$ 783.76	$ 276.36	$ 394.04	0.1	147.88	$ 40,868	$ 58,272
15	Total -	$ 774.23	$ 414.09	$ 159.07	$ 270.58	1,140.9	3,880.5	$ 617,286	$ 1,050,015
16									
17	Large GS + 4 MW (sec)	$ -	$ -	$ 9.51	$ 20.50	-	3,599.23	$ 34,238	$ 73,802
18	Large GS + 4 MW (pri)	$ -	$ -	$ 7.38	$ 15.92	-	4,636.55	$ 34,238	$ 73,802
								$ 685,763	$ 1,197,619

	Commitment	Demand	Total
Poles	$ 883,336	$ 685,763	$ 1,569,099
Conductor	$ 472,444	$ 1,197,619	$ 1,670,063
Total	$ 1,355,781	$ 1,883,381	$ 3,239,162

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)

XFMR 1

PacifiCorp
Oregon Marginal Cost Study
Transformer Commitment Costs

Line	Customer Type	(A) Percent of Customers	(B) Dollars / Tran.	(C) Weighted $ / Tran.	(D) # Cust. / Tran.	(E) Transformer $ / Cust.	(F) Average Customers	(G) Tot. Trans. Commitment $
				(A) x (B)		(C) / (D)		(E) x (F)
1	Res - Schedule 4	100.00%	253.05	253.05	3.99	$63.44	517,740	$32,845,426
2								
3	GS - Schedule 23							
4	1 Phase	81.92%	253.05	207.30	3.13	$66.16		
5	3 Phase	18.08%	804.15	145.38	3.34	$43.55		
6	0-15 kW	100.00%				$109.71	70,266	$7,708,867
7								
8	1 Phase	47.08%	253.05	119.14	3.13	$38.03		
9	3 Phase	52.92%	804.15	425.54	3.34	$127.46		
10	15+ kW	100.00%				$165.49	12,466	$2,062,957
11								
12	Primary	100.00%	-	-	-	0	90	$0
13								
14	GS - Schedule 28							
15	1 Phase	27.68%	253.05	70.04	1.29	$54.12		
16	3 Phase	72.32%	804.15	581.58	1.27	$457.62		
17	0-50 kW	100.00%				$511.74	4,681	$2,395,456.24
18								
19	1 Phase	13.61%	253.05	34.44	1.29	$26.61		
20	3 Phase	86.39%	804.15	694.72	1.27	$546.64		
21	51-100 kW	100.00%				$573.26	3,686	$2,113,025
22								
23	1 Phase	2.02%	253.05	5.11	1.29	$3.95		
24	3 Phase	97.98%	804.15	787.92	1.27	$619.98		
25	100 + kW	100.00%				$623.93	2,121	$1,323,352
26								
27	Primary	100.00%	-	-	-	0	73	$0
28								
29	GS - Schedule 30							
30	1 Phase	0.00%	253.05	-	1.10	$0.00		
31	3 Phase	100.00%	804.15	804.15	1.08	$742.79		
32	0-300 kW	100.00%				$742.79	231	$171,585
33								
34	1 Phase	0.13%	253.05	0.33	1.10	$0.30		
35	3 Phase	99.87%	804.15	803.12	1.08	$741.84		
36	300+ kW	100.00%				$742.14	593	$440,089
37								
38	Primary	100.00%	-	-	0.00	0	56	$0
39								
40	LPS - Schedule 48							
41	1 - 4 MW (sec)	100.00%	804.15	804.15	1.07	$750.75	97	$72,823
42	1 - 4 MW (pri)	100.00%	-	-	0.00	$0.00	60	$0
43	> 4 MW (sec)	100.00%	804.15	804.15	1.07	$750.75	2	$1,502
44	> 4 MW (pri)	100.00%	-	-	0.00	$0.00	29	$0
45	Trans (trn)	100.00%	-	-	0.00	$0.00	7	$0
46								
47	Schedule 41- Irrigation							
48	1 Phase	14.40%	253.05	36.45	1.39	$26.19		
49	3 Phase	85.60%	804.15	688.32	1.21	$568.48		
50	Total	100.00%				$594.67	7,894	$4,694,319

XFMR 2

PacifiCorp
Oregon Marginal Cost Study
Transformer Demand Costs

Line	Customer Type		(A) Weighted $ / kW	(B) Transformer Peak kW	(C) Tot. Trans. Demand $ (A) x (B)
1	Res - Schedule 4	(sec)	$1.14	3,301,675	$3,774,903
2					
3	GS - Schedule 23				
4	0-15 kW	(sec)	$1.14	252,181	$288,326
5	15+ kW	(sec)	$1.14	161,849	$185,047
6	Primary	(pri)	$0.00	0	$0
7					
8	GS - Schedule 28				
9	0-50 kW	(sec)	$1.14	130,267	$148,939
10	51-100 kW	(sec)	$1.14	234,791	$268,444
11	100 + kW	(sec)	$1.14	294,519	$336,733
12	Primary	(pri)	$0.00	0	$0
13					
14	GS - Schedule 30				
15	0-300 kW	(sec)	$1.14	43,526	$49,765
16	300+ kW	(sec)	$1.14	277,617	$317,408
17	Primary	(pri)	$0.00	0	$0
18					
19					
20	LPS - Schedule 48				
21	1 - 4 MW	(sec)	$1.14	114,669	$131,104
22	1 - 4 MW	(pri)	$0.00	0	$0
23	> 4 MW	(sec)	$1.14	13,742	$15,711
24	> 4 MW	(pri)	$0.00	0	$0
25	Trans	(trn)	$0.00	0	$0
26					
27	Irrigation - Schedule 41 (Average)				
28	Secondary	(sec)	$1.14	154,759	$176,941
29					
30	Totals			4,979,596	$5,693,321

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 2021	(E) Annualized $ @ 7.58%
			(A) / 0.95		(B) or (C) x 1.0392	(D) x 7.58%
1	1 Phase $/kW	$13.79	$14.51		$15.08	$1.14
2						
3	3 Phase $/kW	$13.79	$14.51		$15.08	$1.14
4						
5	1 Phase			$3,212.47	$3,338.40	$253.05
6	$/Transformer					
7						
8	3 Phase			$6,996.24		
9	Dummy Variable					
10						
11	3 Phase			$10,208.71	$10,608.89	$804.15
12	$/Transformer					

Index		Escalation Factor
2019	2021	2019 - 2021
1.0200	1.0600	1.0392

PacifiCorp
Oregon Marginal Cost Study
Distribution O&M Expense
Loading Factor as a Percent of Dist. Plant
(Excluding Meters and St Ltg)

Line	Description	(A) 2009	(B) 2010	(C) 2011	(D) 2012	(E) 2013	(F) 2014	(G) 2015	(H) 2016	(I) 2017	(J) 2018
	Distribution O & M Expenses										
1	Total Distribution O & M Expense	71,075,634	69,087,864	66,557,786	67,568,987	68,689,786	70,580,614	69,136,197	61,535,374	61,513,756	61,139,370
2	Less:										
3	585 St Ltg & Signal Systems	59,174	58,882	63,875	60,545	54,154	61,627	58,974	64,715	39,416	64,984
4	586 Meter Expense	2,878,301	2,873,361	3,548,094	3,194,944	2,991,325	3,120,160	2,616,262	1,645,292	1,079,103	883,546
5	587 Customer Installation Expense	4,456,390	4,466,370	4,633,258	4,311,287	4,352,166	4,244,231	4,157,616	5,227,622	5,089,251	5,107,333
6	596 Main. of St Ltg & Signal Systems	1,008,869	1,065,645	1,251,031	1,084,668	1,057,829	918,033	896,454	953,051	879,053	889,400
7	597 Main. of Meters	1,465,615	1,360,896	1,386,968	1,556,466	1,628,742	1,653,908	1,198,881	10,098	59,787	85,408
8											
9	Total Adjusted Distribution O & M Expense	61,207,285	59,262,711	55,674,560	57,361,078	58,605,569	60,582,655	60,208,010	53,634,596	54,367,145	54,108,699
10	Line 1 - (Lines 3 through 7)										
11											
12											
13	Distribution Plant										
14	Total Distribution Plant	1,645,851,699	1,694,776,599	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
15	Less:										
16	370 Meters	60,319,849	60,008,209	59,771,898	59,665,589	59,706,364	60,110,283	60,993,623	62,541,755	65,791,804	76,927,946
17	373 Street Lighting	21,494,031	21,743,089	21,961,746	22,297,246	22,570,478	22,805,367	23,072,497	23,284,230	23,564,547	23,857,078
18											
19	Adjusted Distribution Plant	1,564,037,819	1,613,025,300	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
20	Line 14 - Line 16 - Line 17										
21											
22											
23	O & M Expense Loading Factor										
24	Distribution O & M Loading	3.91%	3.67%	3.37%	3.38%	3.37%	3.40%	3.29%	2.85%	2.79%	2.67%
25	Line 9 / Line 19										
26											
27	Average Distribution O & M Loading	3.27%									
28	Average of Line 24										
29											
30	Distribution Annual Charge	7.58%									
31											
32	Annualized Distribution O & M Loading Factor	43.14%									
33	Line 27 / Line 30										

Footnotes:
Source: FERC Form 1 (State of Oregon) & Results of Operations

Services 1

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	(C) Overhead Service Drop Cost	(D) Underground Service Drop Cost	(E) % Overhead	(F) % Underground	(G) Weighted Service Drop Cost	(H) Weighted Service Drop Cost 1 & 3 Phase	(I) Weighted Service Drop Cost 1 Phase	(J) Weighted Service Drop Cost 3 Phase
			(A) / (A,Ttl)						(B) x (E)		
1	Res - Schedule 4	504,987	100.00%					$713	$713	$713	
2	Annualized - Line 1 x 7.58%								$54	$54	
3											
4	GS - Schedule 23										
5	0-15 kW										
6	kW = 0, 1 Phase	36,709	52.18%	$902	$734	62.8%	37.2%	$839	$438	$535	
7	kW = 0, 3 Phase	1,205	1.71%	$1,105	$1,009	62.8%	37.2%	$1,069	$18		$101
8	kW > 1, 1 Phase	20,925	29.74%	$1,012	$783	62.8%	37.2%	$927	$276	$336	
9	kW > 1, 3 Phase	11,514	16.37%	$1,203	$1,084	62.8%	37.2%	$1,159	$190		$1,049
10	Total 0-15 kW	70,353	100.00%						$922	$871	$1,150
11	Annualized - Line 10 x 7.58%								$70	$66	$87
12											
13	15+ kW										
14	1 Phase	5,876	47.08%	$1,810	$1,385	62.8%	37.2%	$1,652	$778	$1,652	
15	3 Phase	6,605	52.92%	$2,167	$1,986	62.8%	37.2%	$2,099	$1,111		$2,099
16	Total 15+ kW	12,481	100.00%						$1,889	$1,652	$2,099
17	Annualized - Line 16 x 7.58%								$143	$125	$159
18											
19	Primary										
20	12.47 KV 4-wire Wye	90	100.00%					$0			
21	Annualized - (Line 20) x 7.58%							$0	$0	$0	$0
22											
23	GS - Schedule 28										
24	0-50 kW										
25	1 Phase	1,261	27.68%	$1,810	$1,385	42.9%	57.1%	$1,568	$434	$1,568	
26	3 Phase	3,294	72.32%	$2,167	$1,986	42.9%	57.1%	$2,063	$1,492		$2,063
27	Total 0-50 kW	4,555	100.00%						$1,926	$1,568	$2,063
28	Annualized - Line 27 x 7.58%								$146	$119	$156
29											
30	51-100 kW										
31	1 Phase	488	13.61%	$1,810	$1,385	42.9%	57.1%	$1,568	$213	$1,568	
32	3 Phase	3,099	86.39%	$2,167	$1,986	42.9%	57.1%	$2,063	$1,783		$2,063
33	Total 51-100 kW	3,587	100.00%						$1,996	$1,568	$2,063
34	Annualized - Line 33 x 7.58%								$151	$119	$156
35											
36	100 + kW										
37	1 Phase	42	2.02%	$3,314	$4,204	42.9%	57.1%	$3,822	$77	$3,822	
38	3 Phase	2,023	97.98%	$3,855	$3,942	42.9%	57.1%	$3,905	$3,826		$3,905
39	Total 100 + kW	2,064	100.00%						$3,903	$3,822	$3,905
40	Annualized - Line 39 x 7.58%								$296	$290	$296
41											
42	Primary										
43	12.47 KV 4-wire Wye	71	100.00%					$0	$0		$0
44	Annualized - (Line 43) x 7.58%								$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	(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
			(A) / (A,Ttl)						(B) x (E)
1	GS - Schedule 30								
2									
3	0-300 kW								
4	1 Phase	-	0.00%	$3,314	$4,204	19.5%	80.5%	$4,030	$0.00
5	3 Phase	225	100.00%	$3,855	$3,942	19.5%	80.5%	$3,925	$3,924.90
6	Total 0-300 kW	225	100.00%						$3,924.90
7	Annualized - Line 6 x 7.58%								$297.51
8									
9	300+ kW								
10	1 Phase	1	0.13%	$8,501	$7,305	19.5%	80.5%	$7,537	$9.69
11	3 Phase	578	99.87%	$8,501	$7,305	19.5%	80.5%	$7,537	$7,527.62
12	Total 300+ kW	579	100.00%						$7,537.31
13	Annualized - Line 12 x 7.58%								$571.33
14									
15	Primary								
16	12.47 KV 4-wire Wye	55	100.00%					$0	$0.00
17	Annualized - Line 16 x 7.58%								$0.00
18									
19	LPS - Schedule 48								
20	1 - 4 MW (sec)	96	100.00%		$25,839	0.0%	100.0%	$25,839	$25,838.67
21	Annualized - Line 20 x 7.58%								$1,958.57
22									
23	1 - 4 MW (pri)	60	100.00%					$0	$0.00
24	Annualized - Line 23 x 7.58%								$0.00
25									
26	> 4 MW (sec)	2	100.00%		$25,839	0.0%	100.0%	$25,839	$25,838.67
27	Annualized - Line 26 x 7.58%								$1,958.57
28									
29	> 4 MW (pri)	29	100.00%					$0	$0.00
30	Annualized - Line 29 x 7.58%								$0.00
31									
32	Trans (trn)	7	100.00%					$0	$0.00
33	Annualized - Line 32 x 7.58%								$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 2021	(D) Percent Use	(E) Total Cost per Service
				(B) x 1.0392		
	Residential					
1	OH - small load	#2 Triplex*	$619	$643	31.4%	$201.96
2	OH - all electric	1/0 Triplex	$694	$721	27.7%	$199.80
3	UG - small load	1/0 Triplex	$706	$734	18.0%	$131.95
4	UG - all electric	4/0 Triplex	$753	$783	22.9%	$179.31
5						$713.03
6	0 - 15 kW					
7	kW = 0, 1 Phase	OH - 1/0 Triplex	$868	$902		
8	kW = 0, 1 Phase	UG - 1/0 Triplex	$706	$734		
9	kW = 0, 3 Phase	OH - 1/0 Quadruplex	$1,063	$1,105		
10	kW = 0, 3 Phase	UG - 1/0 Quadruplex	$971	$1,009		
11	kW > 1, 1 Phase	OH - 4/0 Triplex	$974	$1,012		
12	kW > 1, 1 Phase	UG - 4/0 Triplex	$753	$783		
13	kW > 1, 3 Phase	OH - 4/0 Quadruplex	$1,158	$1,203		
14	kW > 1, 3 Phase	UG - 4/0 Quadruplex	$1,043	$1,084		
15						
16	16 - 100 kW					
17	1 Phase	OH - 2-4/0 Triplex	$1,742	$1,810		
18	1 Phase	UG - 2-4/0 Triplex	$1,333	$1,385		
19	3 Phase	OH - 2-4/0 Quadruplex	$2,085	$2,167		
20	3 Phase	UG - 2-4/0 Quadruplex	$1,911	$1,986		
21						
22	101 - 300 kW					
23	1 Phase	3-500 & 350N	$3,189	$3,314		
24	1 Phase	3- 750 & 500 N	$4,045	$4,204		
25	3 Phase	OH - 3-4/0 Quadruplex	$3,710	$3,855		
26	3 Phase	4-350 Quad	$3,793	$3,942		
27						
28	301 - 1000 kW					
29	3 Phase	3-750 kcmil Quad.	$8,180	$8,501		
30	3 Phase	4-750 kcmil Quad.	$7,029	$7,305		
31						
32	1000 kW and Over					
33	Secondary Voltage	12-1000 kcmil Quad.	$24,864	$25,839		
34	Primary Voltage	---	---	---		---

Index 2019	Index 2021	Escalation Factor 2019 - 2021
1.0200	1.0600	1.0392

		Weighted %
Residential Overhead % =	59.1%	
% of Overhead Which Are Small Load=	53.1%	31.4%
% of Overhead Which Are All Electric=	46.9%	27.7%
Residential Underground % =	40.9%	
% of Underground Which Are Small Load=	44.0%	18.0%
% of Underground Which Are All Electric=	56.0%	22.9%
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

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			% of Customers				Weighted Metering Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	(D) x (E)
1	Res - Schedule 4	504,987	100.00%	100.00%		$184	$184.07	$184.07	
2	Annualized - (Line 1) x 7.58%						$13.95	$13.95	
3									
4	GS - Schedule 23								
5	0-15 kW								
6	kW = 0, 1 Phase	36,709	52.18%	63.69%		$174	$90.55	$110.54	
7	kW = 0, 3 Phase	1,205	1.71%		9.48%	$294	$5.04		$27.87
8	kW > 1, 1 Phase	20,925	29.74%	36.31%		$174	$51.62	$63.01	
9	kW > 1, 3 Phase	11,514	16.37%		90.52%	$294	$48.13		$266.22
10	Total 0-15 kW	70,353	100.00%	100.00%	100.00%		$195.34	$173.55	$294.09
11	Annualized - (Line 10) x 7.58%						$14.81	$13.16	$22.29
12									
13	15+ kW								
14	1 Phase	5,876	47.08%	100.00%		$174	$81.71	$173.55	
15	3 Phase W/O KVAR	4,532	36.31%		68.62%	$294	$106.80		$201.82
16	3 Phase With KVAR	2,072	16.60%		31.38%	$294	$48.83		$92.27
17	Total 15+ kW	12,481	100.00%	100.00%	100.00%		$237.34	$173.55	$294.09
18	Annualized - (Line 17) x 7.58%						$17.99	$13.16	$22.29
19									
20	Primary								
21	12.47 KV 4-wire Wye	90	100.00%		100.00%	$11,672	$11,672.29		$11,672.29
22	Annualized - (Line 21) x 7.58%						$884.76	$0.00	$884.76
23									
24	GS - Schedule 28								
25	0-50 kW								
26	kW = 0, 1 Phase	1	0.02%	0.07%		$174	$0.04	$0.13	
27	kW = 0, 3 Phase	4	0.10%		0.14%	$294	$0.29		$0.40
28	kW > 1, 1 Phase	1,260	27.66%	99.93%		$174	$48.00	$173.42	
29	kW > 1, 3 Phase	3,290	72.22%		99.86%	$294	$212.40		$293.69
30	Total 0-50 kW	4,555	100.00%	100.00%	100.00%		$260.73	$173.55	$294.09
31	Annualized - (Line 30) x 7.58%						$19.76	$13.16	$22.29
32									
33	51-100 kW								
34	1 Phase	488	13.61%	100.00%		$174	$23.62	$173.55	
35	3 Phase W/O KVAR	1,413	39.40%		45.60%	$294	$115.87		$134.12
36	3 Phase With KVAR	1,686	46.99%		54.40%	$294	$138.20		$159.97
37	Total 51-100 kW	3,587	100.00%	100.00%	100.00%		$277.69	$173.55	$294.09
38	Annualized - (Line 37) x 7.58%						$21.05	$13.16	$22.29
39									
40	100 + kW								
41	1 Phase	42	2.02%	100.00%		$1,155	$23.31	$1,154.55	
42	3 Phase W/O KVAR	834	40.38%		41.21%	$1,494	$603.43		$615.87
43	3 Phase With KVAR	1,189	57.60%		58.79%	$1,494	$860.77		$878.50
44	Total 100 + kW	2,064	100.00%	100.00%	100.00%		$1,487.51	$1,154.55	$1,494.37
45	Annualized - (Line 44) x 7.58%						$112.75	$87.51	$113.27
46									
47	Primary								
48	12.47 KV 4-wire Wye	71	100.00%		100.00%	$11,672	$11,672.29		$11,672.29
49	Annualized - (Line 48) x 7.58%						$884.76	$0.00	$884.76

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2019.

Meters 2

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs
GS - Schedule 30 / LPS - Schedule 48 / Irrigation - Schedule 41 (Annual)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			% of Customers				Weighted Metering Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	(D) x (E) (F) x 7.58%
1	GS - Schedule 30								
2	0-300 kW								
3	1 Phase	-	0.00%	100.00%		$1,155	$0.00	$1,154.55	
4	3 Phase W/O KVAR	42	18.46%		18.46%	$1,494	$275.90		$275.90
5	3 Phase With KVAR	184	81.54%		81.54%	$1,494	$1,218.47		$1,218.47
6	Total 0-300 kW	225	100.00%	100.00%	100.00%		$1,494.37	$1,154.55	$1,494.37
7	Annualized - (Line 6) x 7.58%						$113.27	$87.51	$113.27
8									
9	300+ kW								
10	1 Phase	1	0.13%	100.00%		$1,330	$1.71	$1,330.18	
11	3 Phase W/O KVAR	120	20.76%		20.79%	$1,494	$310.26		$310.66
12	3 Phase With KVAR	458	79.11%		79.21%	$1,494	$1,182.19		$1,183.71
13	300+ kW	579	100.00%	100.00%	100.00%		$1,494.16	$1,330.18	$1,494.37
14	Annualized - (Line 13) x 7.58%						$113.26	$100.83	$113.27
15									
16	Primary								
17	12.47 KV 4-wire Wye	55	100.00%		100.00%	$11,672	$11,672.29		$11,672.29
18	Annualized - (Line 17) x 7.58%						$884.76		$884.76
19									
20	LPS - Schedule 48								
21	1 - 4 MW (sec)	96	100.00%		100.00%	$1,858	$1,858.09		$1,858.09
22	Annualized - (Line 21) x 7.58%						$140.84		$140.84
23									
24	1 - 4 MW (pri)	60	100.00%		100.00%	$11,672	$11,672.29		$11,672.29
25	Annualized - (Line 24) x 7.58%						$884.76		$884.76
26									
27	> 4 MW (sec)	2	100.00%		100.00%	$1,858	$1,858.09		$1,858.09
28	Annualized - (Line 27) x 7.58%						$140.84		$140.84
29									
30	> 4 MW (pri)	29	100.00%		100.00%	$11,672	$11,672.29		$11,672.29
31	Annualized - (Line 30) x 7.58%						$884.76		$884.76
32									
33	Trans (trn)	7	100.00%		100.00%	$171,400	$171,400.00		$171,400.00
34	Annualized - (Line 33) x 7.58%						$12,992.12		$12,992.12
35									
36									
37	Irrigation - Schedule 41 (Annual)								
38	0 - 50 kW								
39	kW = 0, 1 Phase	-	0.00%	0.00%		$174	$0.00	$0.00	
40	kW = 0, 3 Phase	-	0.00%		0.00%	$294	$0.00		$0.00
41	kW > 1, 1 Phase	954	14.39%	99.90%		$174	$24.97	$173.36	
42	kW > 1, 3 Phase	4,669	70.47%		82.32%	$294	$207.24		$242.11
43									
44	51 - 300 kW								
45	1 Phase	1	0.02%	0.10%		$174	$0.03	$0.18	
46	3 Phase W/O KVAR	216	3.26%		3.81%	$294	$9.59		$11.20
47	3 Phase With KVAR	766	11.56%		13.50%	$294	$33.99		$39.71
48									
49	> 300 kW								
50	1 Phase	-	0.00%	0.00%		$1,330	$0.00	$0.00	
51	3 Phase W/O KVAR	2	0.03%		0.04%	$1,494	$0.45		$0.53
52	3 Phase With KVAR	19	0.28%		0.33%	$1,494	$4.23		$4.94
53	Total Irrigation	6,626	100.00%	100.00%	100.00%		$280.50	$173.54	$298.49
54							$21.26	$13.15	$22.63
55									
56	Primary	-	100.00%		100.00%	$0	$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 2019.

PacifiCorp
Oregon Marginal Cost Study
Incremental Three Phase
Meter and Services Costs

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Meters				Service Drops			
Line	Load Class	Single Phase	Three Phase	Difference	Annualized Difference	Single Phase	Three Phase	Difference	Annualized Difference
				(B) - (A)	(C) x 7.58%			(F) - (E)	(G) x 7.58%
1	Residential	$184.07	$294.09	$110.03	$8.34	$713.03	$1,065.57	$352.54	$26.72
2									
3	0-15 kW	$173.55	$294.09	$120.55	$9.14	$926.70	$1,158.91	$232.21	$17.60
4									
5	16-100 kW	$173.55	$294.09	$120.55	$9.14	$1,652.09	$2,099.43	$447.34	$33.91
6									
7	101-1000 kW	$1,330.18	$1,494.37	$164.19	$12.45	$3,822.10	$3,904.70	$82.60	$6.26
8									
9	1 - 4 MW	N.A.	$1,858.09	N.A.	N.A.	N.A.	$25,838.67	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 2019 Dollars	(C) Indexed to 2021	(D) Percent Use	(E) Total Installed Cost per Meter
	Residential					
1	Small Load	DM221J	$167.00	$173.55	49.38%	$85.70
2	All Electric	DM221K	$187.00	$194.33	50.62%	$98.37
3					100.00%	$184.07
4						
5	0 - 15 kW					
6	kW = 0, 1 Phase	DM221J	$167.00	$173.55	100.00%	$173.55
7						
8	kW = 0, 3 Phase	DM241D	$283.00	$294.09	100.00%	$294.09
9						
10	kW > 1, 1 Phase	DM221J	$167.00	$173.55	100.00%	$173.55
11						
12	kW > 1, 3 Phase	DM241D	$283.00	$294.09	100.00%	$294.09
13						
14						
15	15 - 100 kW					
16	1 Phase	DM221J	$167.00	$173.55	100.00%	$173.55
17						
18	3 Phase wo / KVAR	DM241D	$283.00	$294.09	100.00%	$294.09
19						
20	3 Phase with KVAR	DM241D	$283.00	$294.09	100.00%	$294.09
21						
22						
23	100 - 300 kW					
24	1 Phase	DM231FBB	$1,111.00	$1,154.55	100.00%	$1,154.55
25						
26	3 Phase wo / KVAR	DM271DEC	$1,438.00	$1,494.37	100.00%	$1,494.37
27						
28	3 Phase with KVAR	DM271DEC	$1,438.00	$1,494.37	100.00%	$1,494.37
29						
30						
31	300-1000 kW					
32	W/O KVAR, 1 Phase	DM231FFE	$1,280.00	$1,330.18	100.00%	$1,330.18
33						
34	W/O KVAR, 3 Phase	DM271DEC	$1,438.00	$1,494.37	100.00%	$1,494.37
35						
36	W/KVAR, 3 Phase	DM271DEC	$1,438.00	$1,494.37	100.00%	$1,494.37
37						
38						
39	1000 kW and over					
40	Secondary Volt	DM271AEG	$1,788.00	$1,858.09	100.00%	$1,858.09
41						
42	Primary Metering					
43	13.8 KV 3-wire	DM101ACBA	$8,706.00	$9,047.28		$9,047.28
44	12.47 KV 4-wire Wye	DM121ACJAD	$11,232.00	$11,672.29		$11,672.29
45	24.9 KV 4-wire Wye	DM121BFIAD	$16,544.00	$17,192.52		$17,192.52
46	35 KV 4-wire Wye	DM131BBAH	$22,612.00	$23,498.39		$23,498.39

Index		Escalation Factor
2019	2021	2019 - 2021
1.0200	1.0600	1.0392

Meters 5

PacifiCorp
Oregon Marginal Cost Study
Distribution Meters Expense
Loading Factor

Line	Description	(A) 2009	(B) 2010	(C) 2011	(D) 2012	(E) 2013	(F) 2014	(G) 2015	(H) 2016	(I) 2017	(J) 2018
	Distribution Meters Expenses										
1	586 Meter Expense	2,878,301	2,873,361	3,548,094	3,194,944	2,991,325	3,120,160	2,616,262	1,645,292	1,079,103	883,546
2	597 Main. of Meters	1,465,615	1,360,896	1,386,968	1,556,466	1,628,742	1,653,908	1,198,881	10,098	59,787	85,408
3											
4	Total Adjusted Distribution Meters Expense	4,343,916	4,234,257	4,935,062	4,751,410	4,620,067	4,774,068	3,815,143	1,655,390	1,138,890	968,955
5	Line 1 + Line 2										
6											
7											
8											
9	Distribution Meters										
10	370 Meters	60,319,849	60,008,209	59,771,898	59,665,589	59,706,364	60,110,283	60,993,623	62,541,755	65,791,804	76,927,946
11											
12											
13											
14	Meters Expense Loading Factor										
15	Meter O&M Loading	7.20%	7.06%	8.26%	7.96%	7.74%	7.94%	6.25%	2.65%	1.73%	1.26%
16	Line 4 / Line 10										
17											
18	Average Meter O&M Loading	5.81%									
19	Average of Line 15										
20											
21	Distribution Annual Charge	7.58%									
22											
23	Annualized Meter O&M Loading Factor	$\boxed{76.58\%}$									
24	Line 18 / Line 21										

PacifiCorp
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	8,390	10,850	822	4,037	812	862	57	11	-	586	364	-	30	11	5,950	1,456	348		
2	Avg Lamp kW @ Input	0.043	0.056	0.083	0.096	0.150	0.205	0.056	0.083	0.043	0.056	0.083	0.096	0.150	0.205	0.044	0.110	0.167		
3	Peak kW @ Input-Distribution																		278	42
4	Peak kW @ Input-Transformer																		3,108	1,660
5																				
6	Annual kWh @ Sales	838,975	1,985,520	243,213	1,667,315	426,388	592,884	10,416	3,330	-	107,238	107,744	-	15,750	7,568	1,326,943	601,259	239,481	12,045,888	1,457,127
7	Monthly kWh Usg @ Sales per Lamp	8	15	25	34	44	57	15	25	8	15	25	34	44	57	19	34	57		
8	Losses	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001	1.1001
9	Annual kWh @ Input	922,923	2,184,191	267,549	1,834,147	469,052	652,208	11,458	3,663	-	117,968	118,525	-	17,326	8,325	1,459,717	661,421	263,444	13,251,200	1,602,927
10	Monthly kWh Usg @ Input per Lamp	9	17	27	38	48	63	17	27	9	17	27	38	48	63	20	38	63		
11																				
12																				
13	Gen $/kWh @ Input	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280	$0.03280
14	Transm $/kWh @ Input	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001
15																				
16	Distribution-Poles ($/kW)	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79	$24.79
17	Index	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392
18	Revised Distribution-Poles, incl. Annualization @ 7.58% ($/kW)	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76	$25.76
19																				
20	Distribution-Conductor ($/kW)	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79	$37.79
21	Index	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392
22	Revised Distribution-Conductor, incl. Annualization @ 7.58% ($/kW)	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27	$39.27
23																				
24	Distribution-Transformer ($/kW)	$9.05	$9.05	$9.05	$9.05	$9.05	$9.05	$9.05	$9.05	$9.05	$9.05	$9.05	$9.05	$9.05	$9.05	$9.05	$9.05	$9.05	$14.51	$14.51
25	Index	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392
26	Revised Distribution-Transformer, incl. Annualization @ 7.58% ($/kW)	$9.40	$9.40	$9.40	$9.40	$9.40	$9.40	$9.40	$9.40	$9.40	$9.40	$9.40	$9.40	$9.40	$9.40	$9.40	$9.40	$9.40	$1.64	$1.64
27																				
28	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							$847.47	$941.52	$1,092.52		
29	Index	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392							1.0392	1.0392	1.0392		
30	Revised Distribution-Lighting Installations, incl. Annualization @ 7.58%	$76.40	$81.58	$81.93	$82.67	$87.25	$106.17	$233.22	$233.22							$66.76	$74.17	$86.06		
31																				
32	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		
33	Index	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392	1.0392		
34	Revised Distribution-Lighting O&M	$80.88	$84.30	$84.53	$85.02	$87.09	$104.71	$61.36	$61.36	$80.88	$84.30	$84.53	$85.02	$87.09	$104.71	$42.53	$46.44	$53.47		
35																				
36	Monthly Cost Per Company-Owned Lamp																			
37	Generation Energy	$0.30	$0.55	$0.89	$1.24	$1.58	$2.07	$0.55	$0.89	$0.30	$0.55	$0.89	$1.24	$1.58	$2.07	$0.67	$1.24	$2.07		
38	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		
39																				
40	Distribution-Poles	$0.09	$0.12	$0.18	$0.21	$0.32	$0.44	$0.12	$0.18	$0.09	$0.12	$0.18	$0.21	$0.32	$0.44	$0.10	$0.24	$0.36		
41	Distribution-Conductor	$0.14	$0.18	$0.27	$0.31	$0.49	$0.67	$0.18	$0.27	$0.14	$0.18	$0.27	$0.31	$0.49	$0.67	$0.15	$0.36	$0.55		
42	Distribution-Transformer	$0.03	$0.04	$0.07	$0.07	$0.12	$0.16	$0.04	$0.07	$0.03	$0.04	$0.07	$0.07	$0.12	$0.16	$0.03	$0.09	$0.13		
43																				
44	Distribution-Lighting	$13.11	$13.82	$13.87	$13.97	$14.53	$17.57	$24.55	$24.55	$6.74	$7.02	$7.04	$7.09	$7.26	$8.73	$9.11	$10.05	$11.63		
45																				
46	Customer - Billing	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$1.65	$1.65	$1.65		
47	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		
48	Customer - Other	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.51	$0.51	$0.51		
49	Total Lighting Marginal Cost																			
50	Generation Energy	$30,272	$71,641	$8,776	$60,160	$15,385	$21,392	$376	$120	$0	$3,869	$3,888	$0	$568	$273	$47,879	$21,695	$8,641	$434,639	$52,576
51	Transmission Energy	$12	$28	$3	$24	$6	$8	$0	$0	$0	$2	$2	$0	$0	$0	$19	$9	$3	$172	$21
52																				
53	Distribution - Poles	$9,360	$15,519	$1,763	$9,932	$3,136	$4,561	$81	$24	$0	$838	$781	$0	$116	$58	$6,809	$4,128	$1,494	$7,161	$1,089
54	Distribution - Conductor	$14,270	$23,660	$2,688	$15,142	$4,782	$6,953	$124	$37	$0	$1,278	$1,191	$0	$177	$89	$10,381	$6,293	$2,277	$10,917	$1,661
55	Distribution - Transformer	$3,417	$5,665	$643	$3,625	$1,145	$1,665	$30	$9	$0	$306	$285	$0	$42	$21	$2,485	$1,507	$545	$5,087	$2,717
56																				
57	Distribution-Lighting	$1,319,619	$1,799,702	$136,773	$677,002	$141,593	$181,725	$16,766	$3,314	$0	$49,398	$30,769	$0	$2,613	$1,152	$650,329	$175,588	$48,567		
58																				
59	Customer - Billing	$8,686	$11,233	$851	$4,180	$841	$892	$59	$12	$0	$607	$377	$0	$31	$11	$117,463	$28,739	$6,871	$7,648	$2,661
60	Customer - Metering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,748
61	Customer - Other	$2,675	$3,460	$262	$1,287	$259	$275	$18	$4	$0	$187	$116	$0	$10	$4	$36,177	$8,851	$2,116	$2,355	$820
62	Total Lighting Marginal Cost by Schedule																			

Line	Units Description / Function	Schs. 51 & 15	Sch. 53	Sch. 54	Total
63					
64	Generation Energy	$294,935	$434,639	$52,576	$782,150
65	Transmission Energy	$117	$172	$21	$310
66					
67	Distribution - Poles	$58,599	$7,161	$1,089	$66,849
68	Distribution - Conductor	$89,339	$10,917	$1,661	$101,917
69	Distribution - Transformer	$21,390	$5,087	$2,717	$29,194
70					
71	Distribution-Lighting	$5,234,909			$5,234,909
72					
73	Customer - Billing	$180,852	$7,648	$2,661	$191,161
74	Customer - Metering	$0	$0	$2,748	$2,748
75	Customer - Other	$55,700	$2,355	$820	$58,875

Index		Escalation Factor
2019	2021	2019 - 2021
1.0200	1.0600	1.0392

Lgt 2

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	1,097	6,045	302	105
2						
3						
4	$/Unit	Meters				$26.15
5	$/Unit	Billing	$25.32	$25.32	$25.32	$25.32
6	$/Unit	Meter Reading	$0.00	$0.00	$0.00	$0.00
7	$/Unit	Customer Service / Other	$7.80	$7.80	$7.80	$7.80
8						
9						
10	$	Meters				$2,748
11	$	Billing	$27,779	$153,073	$7,648	$2,661
12	$	Meter Reading	$0	$0	$0	$0
13	$	Customer Service / Other	$8,556	$47,144	$2,355	$820
14						
15						
16	Units	Forecast Average Annual Lamps	26,831	7,754		
17						
18						
19	$/Unit	Billing / Forecast Average Annual Lamps	$1.04	$19.74		
20	$/Unit	Meter Reading / Forecast Average Annual Lamps	$0.00	$0.00		
21	$/Unit	Customer Service / Other / Forecast Average Annual Lamps	$0.32	$6.08		

Lgt 3

Company-Owned LED Lighting Maintenance Costs

	Hours	Rate	Street Lights: 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)	Area Lights: 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)
Replace Pole (wood)		$183.56	30'	30'	30'	30'	35'	40'			30'	30'	35'
Material Cost			$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'			
Material Cost			$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'					
Material Cost			$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													
Material Cost			$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													
Material Cost			$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													
Material Cost			$220.48	$286.14	$290.61	$300.08	$358.12	$598.33	$900.00	$900.00	$149.95	$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	$370.22	$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	$847.47	$941.52	$1,092.52

Lgt 4

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

Area Light Counts by Type

Class	Level	Unit Count	% Barn Style	% Flood Style	Est. Barn Style Count	Est. Flood Style Count	Est. Barn Style Count / Total
Residential	1	27,135	80%	20%	21,708	5,427	
Residential	2	782	0%	100%	-	782	
Residential	3	-	0%	100%	-	-	
Commercial	1	42,956	60%	40%	25,774	17,182	
Commercial	2	15,789	0%	100%	-	15,789	
Commercial	3	3,848	0%	100%	-	3,848	
Industrial	1	1,038	60%	40%	623	415	
Industrial	2	842	0%	100%	-	842	
Industrial	3	229	0%	100%	-	229	
PSH	1	276	60%	40%	166	110	
PSH	2	57	0%	100%	-	57	
PSH	3	100	0%	100%	-	100	
Overall	1				48,270	23,135	67.6%
Overall	2				-	17,470	0.0%
Overall	3				-	4,177	0.0%

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer and Metering Expenses
December 2021 Dollars

Line	Description	(A) Actual 2014 Dollars	(B) Actual 2015 Dollars	(C) Actual 2016 Dollars	(D) Actual 2017 Dollars	(E) Actual 2018 Dollars	(F) Adjusted 2021 Dollars
							[(A) x 1.1632+ (B) x 1.1383+ (C) x 1.1140+ (D) x 1.0902+ (E) x 1.0669] / 5
	Customer Accounting						
1	901 Supervision	794,473	1,006,165	737,727	744,030	776,328	$906,136
2	902 Meter Reading Expense	9,025,205	8,911,881	9,736,750	10,573,506	9,772,620	$10,688,579
3	903 Cust Records & Collection	16,673,071	15,697,569	15,397,727	15,201,207	15,706,759	$17,549,125
4	904 Uncollectible Accounts	4,921,762	3,843,290	4,289,333	6,179,088	4,639,879	$5,312,971
5	905 Misc Cust Acct Expense	47,599	10,485	12,890	3,926	4,809	$18,215
6	Total	31,462,110	29,469,390	30,174,427	32,701,757	30,900,395	$34,475,026
7							
8	Customer Service & Info Expense						
9	907 Supervision	45,549	81,966	88,021	90,935	36,862	$76,561
10	908 Cust Assistance Expense	2,253,219	2,371,310	2,697,239	2,512,406	2,730,139	$2,795,348
11	909 Info & Instructional Expense	1,164,388	1,079,142	887,624	857,417	2,077,877	$1,344,652
12	910 Misc Cust Svc & Info Expense	30,048	4,931	17,342	1,002	12,955	$14,960
13	Total	3,493,204	3,537,350	3,690,225	3,461,760	4,857,833	$4,231,521
14							$38,706,547
15	Distribution Expenses						
16	586 Meter Expenses	$3,120,160	$2,616,262	$1,645,292	$1,079,103	$883,546	$2,111,882
17	597 Meter Maintenance	$1,653,908	$1,198,881	$10,098	$59,787	$85,408	$691,212
18		$4,774,068	$3,815,143	$1,655,390	$1,138,890	$968,955	$2,803,094
19							
20							
21	(1) Inflation Adjustment -	1.1632	1.1383	1.1140	1.0902	1.0669	

Source:
Source: State of Oregon results of operations

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer Accounting Expense
By Schedule
December 2021 Dollars

Line	FERC Account	Description	Calculation Description	(A) Sch. 4 Residential	(B) Sch. 23 General Service	(C) Sch. 28 General Service	(D) Sch. 30 General Service	(E) Sch. 48 General Service	(F) Sch. 41 Irrigation	(G) Streetlighting	(H) Total
1			Average Number of Customers	517,740	82,822	10,562	880	195	4,803	7,549	624,551
2			Write-offs By Schedule	1,601,950	69,333	99,631	53,414	68,803	35,721	-	1,928,854
3											
4											
5	901	Supervision	Account 902 + 903 + 904	$18,979,938	$2,498,592	$597,273	$174,026	$216,684	$204,423	$191,161	$22,862,096
6	901		% of Total 902 + 903 +904	83.02%	10.93%	2.61%	0.76%	0.95%	0.89%	0.84%	100.00%
7	901		Total 901 $	$752,267	$99,031	$23,673	$6,897	$8,588	$8,102	$7,577	$906,136
8	901		$ Per Customer	$1.45	$1.20	$2.24	$7.84	$44.04	$1.69	$1.00	$1.45
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	0.99	1.09	1.09	4.95	0.78	0.90	
17	903		Weighted Customers	517,740	82,015	11,474	956	966	3,768	6,794	623,713
18	903		% of Total $	83.01%	13.15%	1.84%	0.15%	0.15%	0.60%	1.09%	100.00%
19	903		Total 903 $	$14,567,412	$2,307,615	$322,841	$26,898	$27,167	$106,030	$191,161	$17,549,125
20	903		$ Per Customer	$28.14	$27.86	$30.57	$30.57	$139.32	$22.08	$25.32	$28.10
21											
22	904	Uncollectibles	Total 904 $	$4,412,525	$190,977	$274,431	$147,128	$189,517	$98,393	$0	$5,312,971
23	904		% of Write-offs	83.05%	3.59%	5.17%	2.77%	3.57%	1.85%	0.00%	100.00%
24	904		$ Per Customer	$8.52	$2.31	$25.98	$167.19	$971.88	$20.49	$0.00	$8.51
25											
26	905	Misc Cust Acct Expense	Account 902 + 903 + 904	$18,979,938	$2,498,592	$597,273	$174,026	$216,684	$204,423	$191,161	$22,862,096
27	905		% of Total 902 + 903 +904	83.02%	10.93%	2.61%	0.76%	0.95%	0.89%	0.84%	100.00%
28	905		Total 905 $	$15,122	$1,991	$476	$139	$173	$163	$152	$18,215
29	905		$ Per Customer	$0.03	$0.02	$0.05	$0.16	$0.89	$0.03	$0.02	$0.03
30											
31	907-910	Supervision, Cust. Assist.	Average Number of customers	517,740	82,822	10,562	880	195	4,803	7,549	624,551
32	907-910	Info & Instructional Exp.,	% of Total	82.90%	13.26%	1.69%	0.14%	0.03%	0.77%	1.21%	100.00%
33	907-910	Misc Cust Svc & Info Exp.	Total 907-910 $	$3,507,847	$561,144	$71,561	$5,962	$1,321	$32,540	$51,146	$4,231,521
34	907-910		$ Per Customer	$6.78	$6.78	$6.78	$6.78	$6.78	$6.78	$6.78	$6.78
35											
36											
37	901 - 910		Total 901 - 910 $	$23,255,174	$3,160,758	$692,982	$187,024	$226,767	$245,227	$250,035	$28,017,968
38											
39			$ Per Customer	$44.92	$38.16	$65.61	$212.53	$1,162.91	$51.06	$33.12	$44.86

AG Expenses

PacifiCorp
Oregon Marginal Cost Study
Administrative & General Expense
Loading Factor

Year	(A) Administrative and General Expenses (000)	(B) Electric Plant in Service (000)	(C) Admin. & General to Electric Plant In Service Loading Factor (A) / (B)
2009	$162,620	$19,645,569	0.83%
2010	$146,076	$21,775,587	0.67%
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%
10 Year Average A&G to EPIS Loading Factor			0.61%

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) 20 years - Generation	(B) 10 years - Generation	(C) 5 years - Generation	(D) System Transmission	(E) Distribution
1	Levelized Income Taxes	NA	NA	NA	1.07%	0.97%
2	Levelized Property Tax	NA	NA	NA	0.79%	0.72%
3	Total	NA	NA	NA	1.86%	1.69%
4						
5	Levelized Income & Property Taxes	NA	NA	NA	$18.60	$16.90
6	(per $1,000 of Investment)					
7						
8	Expected Life	20	10	5	62	52
9						
10	Nominal Interest Rate	7.68%	7.68%	7.68%	7.68%	7.68%
11						
12	Present Value: Income **	NA	NA	NA	$239.83	$215.45
13	Taxes & Property Taxes per				(PV of $18.60 per year	(PV of $16.90 per year
14	$1,000 of Investment				for 62 years at 7.68%)	for 52 years at 7.68%)
15						
16	Removal Cost Per $1,000 Investment				$166.67	$453.24
17						
18	Present Value: Removal Cost				$1.70	$9.68
19	at End of Useful Life				(PV of $166.67 in	(PV of $453.24 in
20					62 years at 7.68%)	52 years at 7.68%)
21						
22	Investment and Taxes	$1,000.00	$1,000.00	$1,000.00	$1,241.53	$1,225.13
23	w/o PVCD (Line 12 + Line 18 + $1000)					
24						
25	PVCD Factor	NA	NA	NA	0.041498	0.042097
26						
27	PVCD $ (Line 22 x Line 25)	NA	NA	NA	$51.52	$51.57
28						
29	Total (Line 22 + Line 27)	$1,000.00	$1,000.00	$1,000.00	$1,293.05	$1,276.70
30						
31	EOY Annual Charge ***	$78.60	$125.15	$221.47	$68.64	$69.71
32						
33	Annual Economic Carrying	7.86%	12.52%	22.15%	6.86%	6.97%
34	Adm &Gen Expense Loading Factor	0.00%	0.00%	0.00%	0.61%	0.61%
35						
36	Annual Econ Carrying + A&G Loading	7.86%	12.52%	22.15%	7.47%	7.58%

Footnotes:
From Financial Analysis -
** PV = Ln(5) x [1/r - (1/r)/(1+r)^a]

18.60*(1/0.0768-(1/0.0768)/(1+0.0768)^62)
16.90*(1/0.0768-(1/0.0768)/(1+0.0768)^52)

Where:
r = Nominal Interest Rate
a = Expected Investment Life

*** The Annual Charge Formula:

AC% = Ln(11) x k x {1/[1 - 1/(1+k)^a]}/(1+k)

Where:
k = real interest rate = (1 + r) / (1 + i) - 1
i = inflation rate = 2.2%
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	7.68%	Income Taxes		2019	2.30%
2	Borrowing Rate	7.68%	Transmission	1.07%	2020	2.66%
3	Inflation	2.18%	Distribution	0.97%	2021	2.63%
4			Property Taxes		2022	2.52%
5	Real Cost of Capital		Transmission	0.79%	2023	2.39%
6	(1+0.0768)/(1+0.0218)-1 =	5.38%	Distribution	0.72%	2024	2.34%
7					2025	2.31%
8					2026	2.28%
9					2027	2.20%
10					2028	2.17%
11					2029	2.19%
12					2030	2.17%
13					2031	2.13%
14					2032	2.09%
15					2033	2.08%
16					2034	2.07%
17					2035	2.05%
18					2036	2.03%
19					2037	2.01%
20					2038	2.00%
21					2039	2.00%
22					2040	2.00%
23					2021 thru 2040 Average	2.18%

Source:
Cost of Capital/Borrowing Rate: Revenue Requirement (OR Jurisdictional Allocation Model)
Income & Property Taxes: 2019 Use of Facilities Report
Company Official Inflation Rate Forecast, March 2018 Avoided Cost, Table 9

Charge 3

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2 & 62 Year Average Lif
Page 1 of 2

Real Cost of Capital = 5.38%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.0
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0538 ^Year	(C) / (D)	(B)	1.0538 ^62	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.000746	8.19%	0.0819	1.053760	0.077755	0.0819	25.703529	0.003188	0.074568	99.9181
2	0.002158	16.39%	0.1639	1.110411	0.147577	0.1639	25.703529	0.006375	0.141201	99.7542
3	0.003494	16.39%	0.1639	1.170107	0.140048	0.1639	25.703529	0.006375	0.133672	99.5903
4	0.004849	17.55%	0.1755	1.233012	0.142321	0.1755	25.703529	0.006827	0.135494	99.4148
5	0.006259	19.29%	0.1929	1.299299	0.148467	0.1929	25.703529	0.007505	0.140962	99.2219
6	0.007593	19.29%	0.1929	1.369150	0.140893	0.1929	25.703529	0.007505	0.133388	99.0290
7	0.008921	20.30%	0.2030	1.442755	0.140681	0.2030	25.703529	0.007896	0.132784	98.8261
8	0.010322	22.65%	0.2265	1.520318	0.148950	0.2265	25.703529	0.008810	0.140140	98.5996
9	0.011648	22.65%	0.2265	1.602051	0.141351	0.2265	25.703529	0.008810	0.132541	98.3732
10	0.012942	23.39%	0.2339	1.688178	0.138573	0.2339	25.703529	0.009101	0.129471	98.1392
11	0.014323	26.39%	0.2639	1.778935	0.148331	0.2639	25.703529	0.010266	0.138065	97.8754
12	0.015628	26.39%	0.2639	1.874571	0.140763	0.2639	25.703529	0.010266	0.130497	97.6115
13	0.016881	26.81%	0.2681	1.975348	0.135721	0.2681	25.703529	0.010430	0.125291	97.3434
14	0.018232	30.61%	0.3061	2.081543	0.147068	0.3061	25.703529	0.011910	0.135158	97.0373
15	0.019509	30.61%	0.3061	2.193448	0.139565	0.3061	25.703529	0.011910	0.127655	96.7311
16	0.020714	30.61%	0.3061	2.311368	0.132445	0.3061	25.703529	0.011910	0.120535	96.4250
17	0.022028	35.35%	0.3535	2.435628	0.145157	0.3535	25.703529	0.013755	0.131402	96.0715
18	0.023268	35.35%	0.3535	2.566568	0.137751	0.3535	25.703529	0.013755	0.123997	95.7179
19	0.024438	35.35%	0.3535	2.704547	0.130724	0.3535	25.703529	0.013755	0.116969	95.3644
20	0.025688	40.06%	0.4006	2.849944	0.140557	0.4006	25.703529	0.015585	0.124973	94.9638
21	0.026881	40.58%	0.4058	3.003158	0.135127	0.4058	25.703529	0.015788	0.119339	94.5580
22	0.028005	40.58%	0.4058	3.164609	0.128233	0.4058	25.703529	0.015788	0.112445	94.1522
23	0.029187	45.28%	0.4528	3.334739	0.135775	0.4528	25.703529	0.017615	0.118160	93.6994
24	0.030328	46.45%	0.4645	3.514015	0.132190	0.4645	25.703529	0.018072	0.114117	93.2349
25	0.031402	46.45%	0.4645	3.702930	0.125446	0.4645	25.703529	0.018072	0.107373	92.7704
26	0.032510	50.99%	0.5099	3.902000	0.130677	0.5099	25.703529	0.019838	0.110840	92.2605
27	0.033592	52.94%	0.5294	4.111773	0.128741	0.5294	25.703529	0.020595	0.108147	91.7311
28	0.034608	52.94%	0.5294	4.332823	0.122173	0.5294	25.703529	0.020595	0.101579	91.2017
29	0.035638	57.23%	0.5723	4.565756	0.125351	0.5723	25.703529	0.022266	0.103085	90.6294
30	0.036654	60.10%	0.6010	4.811213	0.124910	0.6010	25.703529	0.023381	0.101529	90.0285
31	0.037605	60.10%	0.6010	5.069865	0.118537	0.6010	25.703529	0.023381	0.095156	89.4275
32	0.038555	64.03%	0.6403	5.342422	0.119856	0.6403	25.703529	0.024912	0.094944	88.7872
33	0.039498	67.97%	0.6797	5.629632	0.120732	0.6797	25.703529	0.026443	0.094289	88.1075
34	0.040379	67.97%	0.6797	5.932283	0.114573	0.6797	25.703529	0.026443	0.088130	87.4278
35	0.041243	71.40%	0.7140	6.251204	0.114218	0.7140	25.703529	0.027778	0.086440	86.7138
36	0.042108	76.55%	0.7655	6.587270	0.116207	0.7655	25.703529	0.029781	0.086425	85.9483
37	0.042913	76.55%	0.7655	6.941404	0.110278	0.7655	25.703529	0.029781	0.080497	85.1828
38	0.043689	79.35%	0.7935	7.314575	0.108475	0.7935	25.703529	0.030869	0.077606	84.3894
39	0.044469	85.87%	0.8587	7.707809	0.111408	0.8587	25.703529	0.033408	0.078000	83.5307
40	0.045192	85.87%	0.8587	8.122183	0.105724	0.8587	25.703529	0.033408	0.072316	82.6720
41	0.045877	87.88%	0.8788	8.558833	0.102682	0.8788	25.703529	0.034191	0.068491	81.7931
42	0.046567	95.94%	0.9594	9.018958	0.106371	0.9594	25.703529	0.037324	0.069047	80.8338
43	0.047203	95.94%	0.9594	9.503820	0.100944	0.9594	25.703529	0.037324	0.063620	79.8744
44	0.047795	97.00%	0.9700	10.014748	0.096857	0.9700	25.703529	0.037738	0.059119	78.9044
45	0.048390	106.58%	1.0658	10.553143	0.100994	1.0658	25.703529	0.041465	0.059529	77.8386
46	0.048934	106.58%	1.0658	11.120483	0.095842	1.0658	25.703529	0.041465	0.054376	76.7728
47	0.049428	106.58%	1.0658	11.718323	0.090952	1.0658	25.703529	0.041465	0.049487	75.7070
48	0.049924	117.74%	1.1774	12.348304	0.095351	1.1774	25.703529	0.045808	0.049543	74.5296
49	0.050371	117.74%	1.1774	13.012152	0.090486	1.1774	25.703529	0.045808	0.044678	73.3522
50	0.050771	117.74%	1.1774	13.711688	0.085870	1.1774	25.703529	0.045808	0.040062	72.1747
51	0.051159	127.99%	1.2799	14.448832	0.088582	1.2799	25.703529	0.049795	0.038787	70.8948
52	0.051505	129.13%	1.2913	15.225605	0.084810	1.2913	25.703529	0.050238	0.034573	69.6035
53	0.051807	129.13%	1.2913	16.044138	0.080484	1.2913	25.703529	0.050238	0.030246	68.3123
54	0.052087	138.19%	1.3819	16.906675	0.081735	1.3819	25.703529	0.053762	0.027973	66.9304
55	0.052329	140.45%	1.4045	17.815583	0.078836	1.4045	25.703529	0.054643	0.024193	65.5259
56	0.052531	140.45%	1.4045	18.773353	0.074814	1.4045	25.703529	0.054643	0.020171	64.1214
57	0.052703	147.99%	1.4799	19.782613	0.074810	1.4799	25.703529	0.057577	0.017233	62.6414
58	0.052840	151.23%	1.5123	20.846132	0.072544	1.5123	25.703529	0.058835	0.013709	61.1292
59	0.052940	151.23%	1.5123	21.966826	0.068843	1.5123	25.703529	0.058835	0.010008	59.6169
60	0.053008	157.01%	1.5701	23.147768	0.067831	1.5701	25.703529	0.061086	0.006745	58.0468

Charge 4

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2 & 62 Year Average Life

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.0
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0538 ^Year	(C) / (D)	(B)	1.0538 ^62	(F) / (G)	(E) - (H)	(Given)
61	0.053041	160.87%	1.6087	24.392198	0.065952	1.6087	25.703529	0.062587	0.003365	56.4381
62	0.053041	160.87%	1.6087	25.703529	0.062587	1.6087	25.703529	0.062587	0.000000	54.8294
63	0.053009	164.81%	1.6481	27.085358	0.060847	1.6481	25.703529	0.064118	-0.003271	53.1813
64	0.052943	168.74%	1.6874	28.541474	0.059122	1.6874	25.703529	0.065649	-0.006528	51.4939
65	0.052848	168.74%	1.6874	30.075871	0.056105	1.6874	25.703529	0.065649	-0.009544	49.8065
66	0.052722	170.90%	1.7090	31.692758	0.053923	1.7090	25.703529	0.066488	-0.012565	48.0975
67	0.052566	174.13%	1.7413	33.396569	0.052140	1.7413	25.703529	0.067745	-0.015605	46.3562
68	0.052384	174.13%	1.7413	35.191977	0.049480	1.7413	25.703529	0.067745	-0.018265	44.6149
69	0.052175	174.79%	1.7479	37.083908	0.047133	1.7479	25.703529	0.068001	-0.020868	42.8670
70	0.051940	176.32%	1.7632	39.077548	0.045121	1.7632	25.703529	0.068599	-0.023477	41.1038
71	0.051682	176.32%	1.7632	41.178368	0.042819	1.7632	25.703529	0.068599	-0.025779	39.3406
72	0.051403	176.02%	1.7602	43.392128	0.040565	1.7602	25.703529	0.068481	-0.027916	37.5804
73	0.051105	174.81%	1.7481	45.724900	0.038230	1.7481	25.703529	0.068009	-0.029779	35.8323
74	0.050788	174.81%	1.7481	48.183083	0.036280	1.7481	25.703529	0.068009	-0.031729	34.0843
75	0.050453	174.25%	1.7425	50.773418	0.034318	1.7425	25.703529	0.067790	-0.033472	32.3418
76	0.050111	169.19%	1.6919	53.503011	0.031623	1.6919	25.703529	0.065825	-0.034202	30.6499
77	0.049753	169.19%	1.6919	56.379347	0.030010	1.6919	25.703529	0.065825	-0.035815	28.9579
78	0.049380	169.19%	1.6919	59.410315	0.028479	1.6919	25.703529	0.065825	-0.037346	27.2660
79	0.049014	159.58%	1.5958	62.604230	0.025490	1.5958	25.703529	0.062085	-0.036595	25.6702
80	0.048635	159.58%	1.5958	65.969850	0.024190	1.5958	25.703529	0.062085	-0.037895	24.0744
81	0.048244	159.58%	1.5958	69.516407	0.022956	1.5958	25.703529	0.062085	-0.039129	22.4786
82	0.047871	147.68%	1.4768	73.253627	0.020160	1.4768	25.703529	0.057454	-0.037294	21.0018
83	0.047491	146.35%	1.4635	77.191762	0.018960	1.4635	25.703529	0.056940	-0.037980	19.5383
84	0.047101	146.35%	1.4635	81.341611	0.017993	1.4635	25.703529	0.056940	-0.038947	18.0747
85	0.046738	133.53%	1.3353	85.714558	0.015578	1.3353	25.703529	0.051950	-0.036371	16.7394
86	0.046375	130.32%	1.3032	90.322595	0.014429	1.3032	25.703529	0.050702	-0.036274	15.4362
87	0.046005	130.32%	1.3032	95.178362	0.013692	1.3032	25.703529	0.050702	-0.037010	14.1330
88	0.045664	117.90%	1.1790	100.295176	0.011756	1.1790	25.703529	0.045870	-0.034115	12.9539
89	0.045332	112.58%	1.1258	105.687071	0.010652	1.1258	25.703529	0.043800	-0.033147	11.8281
90	0.044995	112.58%	1.1258	111.368837	0.010109	1.1258	25.703529	0.043800	-0.033691	10.7023
91	0.044687	101.61%	1.0161	117.356055	0.008658	1.0161	25.703529	0.039530	-0.030872	9.6863
92	0.044396	94.29%	0.9429	123.665148	0.007625	0.9429	25.703529	0.036684	-0.029059	8.7434
93	0.044101	94.29%	0.9429	130.313419	0.007236	0.9429	25.703529	0.036684	-0.029448	7.8005
94	0.043832	85.34%	0.8534	137.319103	0.006215	0.8534	25.703529	0.033201	-0.026987	6.9471
95	0.043587	76.39%	0.7639	144.701414	0.005279	0.7639	25.703529	0.029719	-0.024440	6.1832
96	0.043340	76.39%	0.7639	152.480601	0.005010	0.7639	25.703529	0.029719	-0.024709	5.4193
97	0.043112	69.66%	0.6966	160.677999	0.004336	0.6966	25.703529	0.027103	-0.022767	4.7227
98	0.042916	59.58%	0.5958	169.316091	0.003519	0.5958	25.703529	0.023180	-0.019661	4.1269
99	0.042717	59.58%	0.5958	178.418569	0.003339	0.5958	25.703529	0.023180	-0.019841	3.5311
100	0.042533	54.92%	0.5492	188.010398	0.002921	0.5492	25.703529	0.021365	-0.018444	2.9819
101	0.042384	44.03%	0.4403	198.117887	0.002223	0.4403	25.703529	0.017131	-0.014908	2.5416
102	0.042234	44.03%	0.4403	208.768758	0.002109	0.4403	25.703529	0.017131	-0.015022	2.1013
103	0.042092	41.21%	0.4121	219.992222	0.001873	0.4121	25.703529	0.016031	-0.014158	1.6892
104	0.041989	29.90%	0.2990	231.819062	0.001290	0.2990	25.703529	0.011634	-0.010344	1.3902
105	0.041885	29.90%	0.2990	244.281717	0.001224	0.2990	25.703529	0.011634	-0.010410	1.0911
106	0.041784	28.66%	0.2866	257.414367	0.001113	0.2866	25.703529	0.011151	-0.010037	0.8045
107	0.041723	17.48%	0.1748	271.253031	0.000645	0.1748	25.703529	0.006802	-0.006158	0.6297
108	0.041661	17.48%	0.1748	285.835667	0.000612	0.1748	25.703529	0.006802	-0.006190	0.4548
109	0.041598	17.48%	0.1748	301.202268	0.000580	0.1748	25.703529	0.006802	-0.006222	0.2800
110	0.041571	7.55%	0.0755	317.394982	0.000238	0.0755	25.703529	0.002937	-0.002699	0.2045
111	0.041544	7.55%	0.0755	334.458221	0.000226	0.0755	25.703529	0.002937	-0.002711	0.1290
112	0.041517	7.55%	0.0755	352.438784	0.000214	0.0755	25.703529	0.002937	-0.002723	0.0535
113	0.041510	2.09%	0.0209	371.385987	0.000056	0.0209	25.703529	0.000813	-0.000757	0.0326
114	0.041504	1.48%	0.0148	391.351796	0.000038	0.0148	25.703529	0.000577	-0.000539	0.0178
115	0.041499	1.48%	0.0148	412.390973	0.000036	0.0148	25.703529	0.000577	-0.000541	0.0030
116	0.041498	0.30%	0.0030	434.561221	0.000007	0.0030	25.703529	0.000115	-0.000109	0.0000
		100.0000	100.0000							

Charge 5

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2 & 52 Year Average Life

Real Cost of Capital = 5.38%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.0
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0538 ^Year	(C) / (D)	(B)	1.0538 ^52	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.000863	9.77%	0.0977	1.053760	0.092708	0.0977	15.225605	0.006416	0.086292	99.9023
2	0.002494	19.54%	0.1954	1.110411	0.175957	0.1954	15.225605	0.012833	0.163124	99.7069
3	0.004036	19.54%	0.1954	1.170107	0.166980	0.1954	15.225605	0.012833	0.154148	99.5115
4	0.005724	22.65%	0.2265	1.233012	0.183728	0.2265	15.225605	0.014879	0.168849	99.2850
5	0.007343	23.00%	0.2300	1.299299	0.177019	0.2300	15.225605	0.015106	0.161912	99.0550
6	0.008952	24.20%	0.2420	1.369150	0.176752	0.2420	15.225605	0.015894	0.160858	98.8130
7	0.010646	27.00%	0.2700	1.442755	0.187142	0.2700	15.225605	0.017733	0.169409	98.5430
8	0.012245	27.00%	0.2700	1.520318	0.177594	0.2700	15.225605	0.017733	0.159861	98.2730
9	0.013927	30.12%	0.3012	1.602051	0.188028	0.3012	15.225605	0.019784	0.168244	97.9718
10	0.015584	31.46%	0.3146	1.688178	0.186364	0.3146	15.225605	0.020664	0.165700	97.6572
11	0.017171	31.97%	0.3197	1.778935	0.179688	0.3197	15.225605	0.020994	0.158694	97.3375
12	0.018878	36.50%	0.3650	1.874571	0.194711	0.3650	15.225605	0.023973	0.170738	96.9725
13	0.020486	36.50%	0.3650	1.975348	0.184778	0.3650	15.225605	0.023973	0.160805	96.6075
14	0.022117	39.33%	0.3933	2.081543	0.188932	0.3933	15.225605	0.025829	0.163102	96.2142
15	0.023762	42.15%	0.4215	2.193448	0.192181	0.4215	15.225605	0.027686	0.164495	95.7927
16	0.025309	42.15%	0.4215	2.311368	0.182376	0.4215	15.225605	0.027686	0.154690	95.3712
17	0.026956	47.76%	0.4776	2.435628	0.196095	0.4776	15.225605	0.031369	0.164726	94.8935
18	0.028524	48.38%	0.4838	2.566568	0.188519	0.4838	15.225605	0.031778	0.156740	94.4097
19	0.030059	50.48%	0.5048	2.704547	0.186666	0.5048	15.225605	0.033158	0.153508	93.9048
20	0.031639	55.38%	0.5538	2.849944	0.194336	0.5538	15.225605	0.036376	0.157960	93.3510
21	0.033119	55.38%	0.5538	3.003158	0.184421	0.5538	15.225605	0.036376	0.148045	92.7972
22	0.034641	60.80%	0.6080	3.164609	0.192113	0.6080	15.225605	0.039930	0.152183	92.1892
23	0.036119	63.12%	0.6312	3.334739	0.189266	0.6312	15.225605	0.041453	0.147813	91.5580
24	0.037519	63.97%	0.6397	3.514015	0.182040	0.6397	15.225605	0.042014	0.140026	90.9183
25	0.038984	71.65%	0.7165	3.702930	0.193506	0.7165	15.225605	0.047061	0.146444	90.2018
26	0.040349	71.65%	0.7165	3.902000	0.183634	0.7165	15.225605	0.047061	0.136572	89.4853
27	0.041705	76.35%	0.7635	4.111773	0.185677	0.7635	15.225605	0.050143	0.135534	88.7218
28	0.043043	81.04%	0.8104	4.332823	0.187034	0.8104	15.225605	0.053225	0.133809	87.9114
29	0.044285	81.04%	0.8104	4.565756	0.177492	0.8104	15.225605	0.053225	0.124267	87.1010
30	0.045568	90.25%	0.9025	4.811213	0.187575	0.9025	15.225605	0.059273	0.128302	86.1986
31	0.046769	91.27%	0.9127	5.069865	0.180023	0.9127	15.225605	0.059945	0.120078	85.2859
32	0.047919	94.60%	0.9460	5.342422	0.177080	0.9460	15.225605	0.062135	0.114946	84.3398
33	0.049065	102.38%	1.0238	5.629632	0.181867	1.0238	15.225605	0.067245	0.114622	83.3160
34	0.050118	102.38%	1.0238	5.932283	0.172589	1.0238	15.225605	0.067245	0.105344	82.2922
35	0.051163	110.78%	1.1078	6.251204	0.177221	1.1078	15.225605	0.072762	0.104459	81.1843
36	0.052148	114.38%	1.1438	6.587270	0.173645	1.1438	15.225605	0.075126	0.098518	80.0405
37	0.053055	115.65%	1.1565	6.941404	0.166614	1.1565	15.225605	0.075960	0.090654	78.8839
38	0.053957	127.08%	1.2708	7.314575	0.173731	1.2708	15.225605	0.083463	0.090268	77.6132
39	0.054771	127.08%	1.2708	7.707809	0.164868	1.2708	15.225605	0.083463	0.081405	76.3424
40	0.055540	133.73%	1.3373	8.122183	0.164649	1.3373	15.225605	0.087833	0.076816	75.0051
41	0.056258	140.38%	1.4038	8.558833	0.164023	1.4038	15.225605	0.092203	0.071820	73.6012
42	0.056892	140.38%	1.4038	9.018958	0.155655	1.4038	15.225605	0.092203	0.063452	72.1974
43	0.057496	152.60%	1.5260	9.503820	0.160571	1.5260	15.225605	0.100228	0.060343	70.6713
44	0.058022	153.96%	1.5396	10.014748	0.153735	1.5396	15.225605	0.101120	0.052615	69.1317

Charge 5

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2 & 52 Year Average Life

Real Cost of Capital = 5.38%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.0
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0538 ^Year	(C) / (D)	(B)	1.0538 ^52	(F) / (G)	(E) - (H)	(Given)
45	0.058481	158.01%	1.5801	10.553143	0.149729	1.5801	15.225605	0.103780	0.045949	67.5516
46	0.058887	167.46%	1.6746	11.120483	0.150588	1.6746	15.225605	0.109987	0.040602	65.8770
47	0.059217	167.46%	1.6746	11.718323	0.142906	1.6746	15.225605	0.109987	0.032919	64.2024
48	0.059487	176.45%	1.7645	12.348304	0.142897	1.7645	15.225605	0.115893	0.027004	62.4378
49	0.059688	180.31%	1.8031	13.012152	0.138569	1.8031	15.225605	0.118424	0.020145	60.6348
50	0.059820	181.46%	1.8146	13.711688	0.132338	1.8146	15.225605	0.119179	0.013159	58.8202
51	0.059887	191.81%	1.9181	14.448832	0.132750	1.9181	15.225605	0.125977	0.006773	56.9021
52	0.059887	191.81%	1.9181	15.225605	0.125977	1.9181	15.225605	0.125977	0.000000	54.9840
53	0.059822	196.50%	1.9650	16.044138	0.122475	1.9650	15.225605	0.129059	-0.006584	53.0190
54	0.059690	201.19%	2.0119	16.906675	0.119002	2.0119	15.225605	0.132141	-0.013139	51.0071
55	0.059498	201.19%	2.0119	17.815583	0.112931	2.0119	15.225605	0.132141	-0.019210	48.9952
56	0.059241	206.97%	2.0697	18.773353	0.110248	2.0697	15.225605	0.135938	-0.025689	46.9255
57	0.058927	207.62%	2.0762	19.782613	0.104948	2.0762	15.225605	0.136359	-0.031411	44.8493
58	0.058558	208.40%	2.0840	20.846132	0.099971	2.0840	15.225605	0.136875	-0.036904	42.7653
59	0.058134	210.23%	2.1023	21.966826	0.095704	2.1023	15.225605	0.138077	-0.042373	40.6630
60	0.057662	210.23%	2.1023	23.147768	0.090821	2.1023	15.225605	0.138077	-0.047256	38.5607
61	0.057146	208.97%	2.0897	24.392198	0.085669	2.0897	15.225605	0.137246	-0.051577	36.4710
62	0.056588	208.42%	2.0842	25.703529	0.081087	2.0842	15.225605	0.136890	-0.055803	34.3868
63	0.055990	207.75%	2.0775	27.085358	0.076703	2.0775	15.225605	0.136450	-0.059747	32.3093
64	0.055372	201.73%	2.0173	28.541474	0.070680	2.0173	15.225605	0.132494	-0.061815	30.2920
65	0.054718	201.73%	2.0173	30.075871	0.067074	2.0173	15.225605	0.132494	-0.065420	28.2747
66	0.054049	196.00%	1.9600	31.692758	0.061844	1.9600	15.225605	0.128731	-0.066887	26.3147
67	0.053369	190.27%	1.9027	33.396569	0.056973	1.9027	15.225605	0.124967	-0.067994	24.4120
68	0.052660	190.27%	1.9027	35.191977	0.054066	1.9027	15.225605	0.124967	-0.070901	22.5093
69	0.051979	176.08%	1.7608	37.083908	0.047481	1.7608	15.225605	0.115645	-0.068165	20.7485
70	0.051279	174.50%	1.7450	39.077548	0.044655	1.7450	15.225605	0.114610	-0.069955	19.0035
71	0.050581	168.77%	1.6877	41.178368	0.040984	1.6877	15.225605	0.110843	-0.069859	17.3158
72	0.049918	155.38%	1.5538	43.392128	0.035809	1.5538	15.225605	0.102055	-0.066245	15.7620
73	0.049237	155.38%	1.5538	45.724900	0.033982	1.5538	15.225605	0.102055	-0.068072	14.2082
74	0.048606	140.58%	1.4058	48.183083	0.029176	1.4058	15.225605	0.092329	-0.063154	12.8024
75	0.047989	134.23%	1.3423	50.773418	0.026437	1.3423	15.225605	0.088161	-0.061724	11.4601
76	0.047368	132.05%	1.3205	53.503011	0.024681	1.3205	15.225605	0.086729	-0.062048	10.1396
77	0.046829	112.42%	1.1242	56.379347	0.019940	1.1242	15.225605	0.073838	-0.053898	9.0153
78	0.046280	112.42%	1.1242	59.410315	0.018923	1.1242	15.225605	0.073838	-0.054915	7.8911
79	0.045774	101.75%	1.0175	62.604230	0.016253	1.0175	15.225605	0.066828	-0.050575	6.8736
80	0.045314	91.08%	0.9108	65.969850	0.013806	0.9108	15.225605	0.059818	-0.046012	5.9628
81	0.044847	91.08%	0.9108	69.516407	0.013102	0.9108	15.225605	0.059818	-0.046717	5.0521
82	0.044467	73.04%	0.7304	73.253627	0.009971	0.7304	15.225605	0.047973	-0.038002	4.3217
83	0.044092	71.04%	0.7104	77.191762	0.009203	0.7104	15.225605	0.046657	-0.037454	3.6113
84	0.043743	65.48%	0.6548	81.341611	0.008050	0.6548	15.225605	0.043004	-0.034955	2.9565
85	0.043459	52.50%	0.5250	85.714558	0.006125	0.5250	15.225605	0.034481	-0.028356	2.4315
86	0.043173	52.50%	0.5250	90.322595	0.005812	0.5250	15.225605	0.034481	-0.028669	1.9065
87	0.042948	40.71%	0.4071	95.178362	0.004277	0.4071	15.225605	0.026736	-0.022459	1.4994
88	0.042749	35.65%	0.3565	100.295176	0.003555	0.3565	15.225605	0.023417	-0.019862	1.1429
89	0.042557	34.17%	0.3417	105.687071	0.003233	0.3417	15.225605	0.022444	-0.019211	0.8012
90	0.042439	20.85%	0.2085	111.368837	0.001872	0.2085	15.225605	0.013692	-0.011820	0.5927
91	0.042320	20.85%	0.2085	117.356055	0.001776	0.2085	15.225605	0.013692	-0.011915	0.3842
92	0.042234	14.92%	0.1492	123.665148	0.001207	0.1492	15.225605	0.009801	-0.008595	0.2350
93	0.042182	9.00%	0.0900	130.313419	0.000691	0.0900	15.225605	0.005911	-0.005220	0.1450
94	0.042129	9.00%	0.0900	137.319103	0.000655	0.0900	15.225605	0.005911	-0.005256	0.0550
95	0.042115	2.49%	0.0249	144.701414	0.000172	0.0249	15.225605	0.001637	-0.001465	0.0301
96	0.042104	1.77%	0.0177	152.480601	0.000116	0.0177	15.225605	0.001162	-0.001046	0.0124
97	0.042097	1.24%	0.0124	160.677999	0.000077	0.0124	15.225605	0.000813	-0.000736	0.0000
			100.0000	53.0009						

Charge 6

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 6/30/2019 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount	
		$		Yrs	%	$	
	TRANSMISSION PLANT						
350.20	Land Rights	211,131,708	R4	75.00	0.00%	-	
352.00	Structures & Improvements	277,949,368	R2.5	75.00	-10.00%	(27,794,937)	
353.00	Station Equipment	2,199,071,199	S0	58.00	-5.00%	(109,953,560)	
353.70	Supervisory Equipment	-				-	
354.00	Towers & Fixtures	1,303,549,778	R4	68.00	-10.00%	(130,354,978)	
355.00	Poles & Fixtures	991,676,069	R2	60.00	-40.00%	(396,670,427)	
356.00	OH Conductors & Devices	1,270,492,579	R3	63.00	-30.00%	(381,147,774)	
356.20	Clearing	-				-	
357.00	UG Conduit	3,787,321	R2	60.00	0.00%	-	
358.00	UG Conductors & Devices	8,035,354	R2	60.00	-5.00%	(401,768)	
359.00	Roads & Trails	11,937,200	R5	70.00	0.00%	-	
	Total Transmission Plant	6,277,630,576		62.32	-16.67%	(1,046,323,443)	
				Use 62 Years			62

	TRANSMISSION PLANT excludes land accounts				
352.00	Structures & Improvements	277,949,368	2.50	4.58%	0.1145
353.00	Station Equipment	2,199,071,199	-	36.25%	-
353.70	Supervisory Equipment	-		0.00%	-
354.00	Towers & Fixtures	1,303,549,778	4.00	21.49%	0.8595
355.00	Poles & Fixtures	991,676,069	2.00	16.35%	0.3269
356.00	OH Conductors & Devices	1,270,492,579	3.00	20.94%	0.6283
356.20	Clearing	-	-	0.00%	-
357.00	UG Conduit	3,787,321	2.00	0.06%	0.0012
358.00	UG Conductors & Devices	8,035,354	2.00	0.13%	0.0026
359.00	Roads & Trails	11,937,200	5.00	0.20%	0.0098
	Total Transmission Plant	6,066,498,868		100.00%	1.9430 **Use R 2**

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 6/30/2019 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount	
		$		Yrs	%	$	
	DISTRIBUTION PLANT (OREGON)						
360.20	Land Rights	5,130,851	S3	55.00	0.00%	-	
361.00	Structures & Improvements	32,577,502	R1.5	60.00	-10.00%	(3,257,750)	
362.00	Station Equipment	258,312,285	R1	55.00	-15.00%	(38,746,843)	
362.70	Supervisory & Alarm Equipment					-	
364.00	Poles, Towers & Fixtures	395,746,642	R1.5	55.00	-100.00%	(395,746,642)	
365.00	OH Conductors & Devices	272,505,215	R0.5	60.00	-70.00%	(190,753,650)	
366.00	UG Conduit	97,778,526	R2.5	70.00	-50.00%	(48,889,263)	
367.00	UG Conductors & Devices	190,342,123	R2.5	58.00	-35.00%	(66,619,743)	
368.00	Line Transformers	460,558,670	R1.5	42.00	-20.00%	(92,111,734)	
369.10	Overhead Services	98,104,148	R1	55.00	-35.00%	(34,336,452)	
369.20	Underground Services	200,105,373	R4	55.00	-40.00%	(80,042,149)	
370.00	Meters	91,508,919	R1	27.00	-4.00%	(3,660,357)	
371.00	I.O.C.P.	2,639,353	L0	25.00	-50.00%	(1,319,676)	
373.00	Street Lighting & Signal Systems	24,072,918	R0.5	44.00	-40.00%	(9,629,167)	
	Total OREGON Distribution Plant	2,129,382,524		51.71	-45.32%	(965,113,427)	
				Use 52 years			52

	DISTRIBUTION PLANT excludes land accounts (OREGON)					
361.00	Structures & Improvements	32,577,502	1.50	1.53%	0.02	Curves:
362.00	Station Equipment	258,312,285	1.00	12.16%	0.12	R=positive
362.70	Supervisory & Alarm Equipment	-		0.00%	0.00	L=negative
364.00	Poles, Towers & Fixtures	395,746,642	1.50	18.63%	0.28	S=0
365.00	OH Conductors & Devices	272,505,215	0.50	12.83%	0.06	
366.00	UG Conduit	97,778,526	2.50	4.60%	0.12	R means right of the standard
367.00	UG Conductors & Devices	190,342,123	2.50	8.96%	0.22	L means left of the standard
368.00	Line Transformers	460,558,670	1.50	21.68%	0.33	S is at the standard
369.10	Overhead Services	98,104,148	1.00	4.62%	0.05	
369.20	Underground Services	200,105,373	4.00	9.42%	0.38	
370.00	Meters	91,508,919	1.00	4.31%	0.04	
371.00	I.O.C.P.	2,639,353	-	0.12%	0.00	
373.00	Street Lighting & Signal Systems	24,072,918	0.50	1.13%	0.01	
	Total OREGON Distribution Plant	2,124,251,674		100.00%	1.62 **Use R 2**	

Losses

PacifiCorp
Oregon Marginal Cost Study
Energy Loss Factors

Line	(A) Voltage Level	(B) Energy Factor	(C) Energy Loss Percent	(D) Demand Factor	(E) Demand Loss Percent
1	Transmission	1.04527	4.53%	1.04259	4.26%
2	Primary	1.06904	6.90%	1.07920	7.92%
3	Secondary	1.10006	10.01%	1.11057	11.06%

Cust Data 1

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh @ Sales
12 Months Ended June 30, 2019 - Actual

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line	Description	Del. Volt	Average Customers	% Total Class	Annual MWh's	% Total Class	Average Billing kW	% Total Class
1	Res - Schedule 4	(sec)	504,987	100.0%	5,483,041	100.0%	4,927,873	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	70,353	84.9%	616,735	51.6%	360,259	60.9%
5	15+ kW	(sec)	12,481	15.1%	578,666	48.4%	231,213	39.1%
6	Sec Subtotal		82,834	100.0%	1,195,401	100.0%	591,472	100.0%
7	Primary	(pri)	90		2,207		812	
8	Total		82,924		1,197,608		592,284	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,555	44.6%	443,392	21.5%	130,267	19.8%
12	51-100 kW	(sec)	3,587	35.1%	688,708	33.3%	234,791	35.6%
13	100 + kW	(sec)	2,064	20.2%	933,234	45.2%	294,519	44.7%
14	Sec Subtotal		10,206	100.0%	2,065,333	100.0%	659,578	100.0%
15	Primary	(pri)	71		26,483		6,851	
16	Total		10,277		2,091,816		666,429	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	225	28.0%	198,747	15.7%	43,526	13.6%
20	300+ kW	(sec)	579	72.0%	1,066,839	84.3%	277,617	86.4%
21	Sec Subtotal		804	100.0%	1,265,586	100.0%	321,143	100.0%
22	Primary	(pri)	55		97,554		30,818	
23	Total		859		1,363,141		351,962	
24								
25	LPS - Schedule 48							
26	1 - 4 MW	(sec)	96	98.0%	518,871	90.1%	114,669	89.3%
27	> 4 MW	(sec)	2	2.0%	57,287	9.9%	13,742	10.7%
28	Sec Subtotal		98	100.0%	576,158	100.0%	128,410	100.0%
29	1 - 4 MW	(pri)	60	67.9%	540,547	34.2%	115,367	37.2%
30	> 4 MW	(pri)	29	32.1%	1,041,870	65.8%	194,774	62.8%
31	Pri Subtotal		89	100.0%	1,582,418	100.0%	310,142	100.0%
32	Trans	(trn)	7		575,018		133,201	
33	Total		194		2,733,594		571,753	
34								
35	Irrigation - Schedule 41 (Average)	(sec)	4,032	100.0%	200,232	100.0%	154,759	100.0%
36								
37	Irrigation - Schedule 41 (Annual)	(sec)	6,626					

Cust Data 2

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh @ Sales
12 Months Ended December 2021 - Normalized

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line	Description	Del. Volt	Average Customers	% Total Class	Annual MWh's	% Total Class	Average Billing kW	% Total Class
1	Res - Schedule 4	(sec)	517,740	100.0%	5,521,127	100.0%	4,927,873	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	70,266	84.9%	581,993	51.6%	360,259	60.9%
5	15+ kW	(sec)	12,466	15.1%	546,068	48.4%	231,213	39.1%
6	Sec Subtotal		82,732	100.0%	1,128,061	100.0%	591,472	100.0%
7	Primary	(pri)	90		2,086		812	
8	Total		82,822		1,130,147		592,284	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,681	44.6%	432,105	21.5%	130,267	19.8%
12	51-100 kW	(sec)	3,686	35.1%	671,177	33.3%	234,791	35.6%
13	100 + kW	(sec)	2,121	20.2%	909,478	45.2%	294,519	44.7%
14	Sec Subtotal		10,489	100.0%	2,012,760	100.0%	659,578	100.0%
15	Primary	(pri)	73		25,965		6,851	
16	Total		10,562		2,038,726		666,429	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	231	28.0%	198,448	15.7%	43,526	13.6%
20	300+ kW	(sec)	593	72.0%	1,065,232	84.3%	277,617	86.4%
21	Sec Subtotal		824	100.0%	1,263,680	100.0%	321,143	100.0%
22	Primary	(pri)	56		97,746		30,818	
23	Total		880		1,361,426		351,962	
24								
25	LPS - Schedule 48							
26	1 - 4 MW	(sec)	97	98.0%	499,959	90.1%	114,669	89.3%
27	> 4 MW	(sec)	2	2.0%	55,199	9.9%	13,742	10.7%
28	Sec Subtotal		99	100.0%	555,158	100.0%	128,410	100.0%
29	1 - 4 MW	(pri)	60	67.9%	527,307	34.2%	115,367	37.2%
30	> 4 MW	(pri)	29	32.1%	1,016,350	65.8%	194,774	62.8%
31	Pri Subtotal		89	100.0%	1,543,656	100.0%	310,142	100.0%
32	Trans	(trn)	7		981,023		133,201	
33	Total		195		3,079,837		571,753	
34								
35	Irrigation - Schedule 41 (Average)	(sec)	4,803	100.0%	221,554	100.0%	154,759	100.0%
36								
37	Irrigation - Schedule 41 (Annual)	(sec)	7,894	100.0%	221,554	100.0%	154,759	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)	-	504,987	0.0000%	100.0000%
2							
3	GS - Schedule 23						
4	0-15 kW		(sec)	12,719	70,353	18.0789%	81.9211%
5	15+ kW		(sec)	6,605	12,481	52.9182%	47.0818%
6	Sec Subtotal			19,324	82,834		
7	Primary		(pri)	90	90	100.0000%	0.0000%
8		Total		19,414	82,924	23.4117%	76.5883%
9							
10	GS - Schedule 28						
11	0-50 kW		(sec)	3,294	4,555	72.3217%	27.6783%
12	51-100 kW		(sec)	3,099	3,587	86.3916%	13.6084%
13	100 + kW		(sec)	2,023	2,064	97.9811%	2.0189%
14	Sec Subtotal			8,416	10,206		
15	Primary		(pri)	71	71	100.0000%	0.0000%
16		Total		8,487	10,277	82.5779%	17.4221%
17							
18	GS - Schedule 30						
19	0-300 kW			225	225	100.0000%	0.0000%
20	300+ kW			578	579	99.8714%	0.1286%
21	Sec Subtotal			803	804		
22	Primary			55	55	100.0000%	0.0000%
23		Total		858	859	99.9133%	0.0867%
24							
25	LPS - Schedule 48						
26	1 - 4 MW		(sec)	96	96	100.0000%	0.0000%
27	1 - 4 MW		(pri)	60	60	100.0000%	0.0000%
28	> 4 MW		(sec)	2	2	100.0000%	0.0000%
29	> 4 MW		(pri)	29	29	100.0000%	0.0000%
30	Trans		(trn)	7	7	100.0000%	0.0000%
31	Total			194	194	100.0000%	0.0000%
32							
33	Irrigation - Schedule 41 (Annual)		(sec)	5,672	6,626	85.5951%	14.4049%

Cust Data 4

PacifiCorp
Oregon Marginal Cost Study
Cutomer Loads at Sales - MW
12 Months Ended December 2021

		(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)		954		1,122		4,928	4	0.67	3,302
2											
3	GS - Schedule 23										
4	0-15 kW	(sec)		85		91		360	3	0.70	252
5	15+ kW	(sec)		84		94		231	3	0.70	162
6	Primary	(pri)		0		0		1	1	1.00	1
7											
8	GS - Schedule 28										
9	0-50 kW	(sec)		65		70		130	1	1.00	130
10	51-100 kW	(sec)		101		114		235	1	1.00	235
11	100 + kW	(sec)		142		162		295	1	1.00	295
12	Primary	(pri)		4		4		7	1	1.00	7
13											
14	GS - Schedule 30										
15	0-300 kW	(sec)		29		34		44	1	1.00	44
16	300+ kW	(sec)		150		165		278	1	1.00	278
17	Primary	(pri)		15		16		31	1	1.00	31
18											
19	LPS - Schedule 48										
20	1 - 4 MW	(sec)		72		77		115	1	1.00	115
21	1 - 4 MW	(pri)		74		79		115	1	1.00	115
22	> 4 MW	(sec)		7		7		14	1	1.00	14
23	> 4 MW	(pri)		127		133		195	1	1.00	195
24	Trans	(trn)		114		115		133	1	1.00	133
25											
26	Irrigation - Sch 41	(sec)		29		33		155	1	1.00	155
27											
28	Customer-Owned Lighting - Sch 53					0		3	1	1.00	3
29											
30	Rec Field Lighting - Sch 54					0		1	1	1.00	1

Cust per Transformer	Coincidence Factor Summer loads	Coincidence Factor 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
(February 17, 2009)

Cust Data 5

PacifiCorp
Oregon Marginal Cost Study
Distribution Substations Monthly Peaks - kW
12 months ended June 2019

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Substation		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Peak Month	Peak Load
Agness Avenue		18,708	17,162	14,746	13,333	15,835	15,827	16,322	16,411	15,773	14,333	13,927	17,229	Jul-18	18,708
Alderwood		13,237	12,273	11,984	10,556	9,547	9,370	16,454	16,676	12,600	13,367	10,652	13,451	Feb-19	16,676
Applegate		8,070	9,539	7,893	8,859	11,492	11,302	12,275	12,795	12,135	8,947	7,742	9,768	Feb-19	12,795
Ashland		15,767	14,989	12,184	9,722	12,777	13,916	14,817	14,976	13,382	10,615	9,619	14,273	Jul-18	15,767
Beall Lane		19,138	18,254	11,589	12,701	15,399	16,386	15,804	16,538	15,511	12,795	15,028	17,414	Jul-18	19,138
Belknap		29,715	28,689	25,759	18,934	21,212	23,097	22,753	23,440	21,174	17,708	20,896	27,043	Jul-18	29,715
Bend Plant		17,573	18,725	11,928	11,524	13,994	15,853	14,513	16,246	15,974	11,238	10,030	13,066	Aug-18	18,725
Bond Street		18,938	20,414	16,965	16,022	12,122	13,623	12,269	13,952	14,385	11,439	10,330	12,989	Aug-18	20,414
Brookhurst		36,650	33,304	28,061	17,714	24,270	25,965	26,797	27,372	24,485	18,401	22,691	33,305	Jul-18	36,650
Bryant		17,248	17,288	14,219	12,814	14,629	70	23,348	37,152	19,446	16,638	14,772	19,228	Feb-19	37,152
Buchanan		24,732	23,987	19,577	19,232	23,772	25,176	24,291	25,437	25,413	19,772	18,828	23,489	Feb-19	25,437
Buckaroo		13,698	24,216	17,995	16,116	18,562	19,396	18,877	20,632	20,490	15,322	15,025	18,175	Aug-18	24,216
Calapooya		18,716	18,274	15,226	16,271	19,630	20,782	19,799	21,054	20,492	16,239	14,930	17,827	Feb-19	21,054
Campbell		23,628	22,337	19,248	14,822	18,868	20,004	19,752	20,319	18,285	14,553	15,314	21,802	Jul-18	23,628
Canyonville		7,446	6,860	5,465	5,607	6,481	6,429	6,319	6,566	6,965	5,572	4,973	6,200	Jul-18	7,446
Cave Junction		11,348	10,273	8,936	11,955	14,863	14,560	15,515	16,168	15,731	13,015	11,793	10,359	Feb-19	16,168
Caveman		20,649	18,374	15,503	10,915	14,159	14,749	15,963	16,039	14,352	11,882	13,564	18,643	Jul-18	20,649
Cherry Lane		6,776	7,190	7,116	7,521	7,220	7,429	7,471	7,320	7,707	7,301	6,849	6,306	Mar-19	7,707
China Hat		17,148	18,072	15,348	16,913	18,908	21,141	19,103	21,827	21,563	16,842	15,613	13,331	Feb-19	21,827
Circle Blvd		14,719	14,483	13,622	13,057	12,807	12,899	12,915	13,067	13,034	13,860	13,921	15,194	Jun-19	15,194
Cleveland Ave.		32,480	30,595	17,376	25,955	28,174	32,161	29,681	32,706	32,672	25,999	23,900	27,273	Feb-19	32,706
Cloake		15,194	14,248	10,260	8,598	10,230	11,385	10,921	11,517	10,608	8,609	9,632	13,763	Jul-18	15,194
Coburg		2,380	2,349	1,797	1,628	1,900	2,162	2,040	2,190	2,088	1,594	1,608	2,290	Jul-18	2,380
Columbia		18,544	18,187	17,291	15,857	38,496	60,847	39,777	50,912	50,296	53,773	36,095	40,796	Dec-18	60,847
Coquille		10,785	10,028	11,455	12,459	14,467	15,963	15,612	16,431	15,893	13,728	12,186	10,447	Feb-19	16,431
Crowfoot		14,240	13,856	11,582	11,492	13,160	14,758	14,108	14,839	14,118	11,973	10,924	14,034	Feb-19	14,839
Cully		17,206	16,642	13,090	11,288	12,832	14,908	14,107	17,848	15,783	12,479	11,719	16,546	Feb-19	17,848
Culver		8,166	8,140	5,992	6,731	7,898	7,939	7,599	8,978	9,095	6,654	5,521	5,905	Mar-19	9,095
Dairy		8,928	8,286	4,876	1,621	1,726	1,923	1,882	2,162	1,839	1,665	6,433	7,747	Jul-18	8,928
Dallas		15,199	14,833	11,669	11,599	14,325	16,720	15,911	17,399	18,073	12,930	11,313	15,323	Mar-19	18,073
Dalreed		37,680	37,791	28,638	12,847	5,094	5,406	4,644	4,179	5,942	12,516	24,533	30,523	Aug-18	37,791
Deschutes		7,069	7,362	5,861	7,704	10,002	11,811	10,083	12,837	11,908	7,726	7,231	5,935	Feb-19	12,837
Devils Lake		20,206	19,672	20,522	24,095	27,731	31,467	32,578	32,400	32,211	25,882	24,021	19,195	Jan-19	32,578
Dixon		3,764	3,635	3,043	2,554	2,651	2,790	2,847	2,844	2,816	2,474	2,900	3,619	Jul-18	3,764
Dodge Bridge		5,457	5,056	4,390	4,054	4,980	5,240	5,584	7,599	7,133	3,227	3,339	4,725	Feb-19	7,599
Dowell		16,316	13,990	11,628	8,563	12,947	11,474	11,908	12,516	11,546	8,749	10,592	14,603	Jul-18	16,316
Easy Valley		19,549	16,036	13,149	10,958	16,978	17,203	15,465	16,349	14,981	11,209	10,938	16,425	Jul-18	19,549
Empire		9,244	9,035	10,653	13,020	15,526	17,324	17,970	19,516	19,300	14,083	12,243	10,246	Feb-19	19,516
Fern Hill		2,301	2,316	2,366	2,812	3,037	3,222	2,790	3,173	2,923	2,358	3,008	1,705	Dec-18	3,222
Fielder Creek		9,293	8,674	7,027	8,333	10,425	10,515	10,626	10,996	10,048	7,877	7,698	8,275	Feb-19	10,996
Foothills Rd		13,836	13,094	10,999	7,818	8,770	9,353	9,688	9,620	8,787	7,717	8,943	12,481	Jul-18	13,836
Garden Valley		14,529	13,782	11,254	8,466	9,960	12,822	14,011	11,483	11,903	8,789	10,360	13,807	Jul-18	14,529
Glendale		12,899	12,964	12,380	13,433	15,325	15,681	15,663	15,402	14,411	9,429	9,680	9,086	Dec-18	15,681
Gold Hill		7,527	6,946	5,754	5,529	7,487	7,904	7,705	8,170	7,451	5,481	5,022	7,088	Feb-19	8,170
Gordon Hollow		3,820	3,649	2,824	2,834	3,852	3,821	3,848	4,962	4,657	2,971	2,948	3,164	Feb-19	4,962
Goshen		5,183	5,100	4,323	4,474	5,594	6,694	6,058	6,295	6,509	4,528	4,122	5,257	Dec-18	6,694
Grant		24,279	19,945	8,200	20,759	24,775	26,562	26,587	28,833	27,595	22,343	18,730	25,536	Feb-19	28,833
Green		13,918	13,265	10,430	10,481	12,916	13,240	13,036	13,657	13,851	10,472	9,464	13,183	Jul-18	13,918
Harrisburg		7,338	7,233	6,009	6,639	7,877	8,417	8,652	8,426	8,438	6,298	6,039	6,866	Jan-19	8,652
Hillview		25,741	24,757	20,811	22,208	25,806	23,825	27,859	26,596	23,490	32,107	19,007	28,245	Apr-19	32,107
Holladay		26,449	27,572	25,724	22,512	21,864	23,673	23,005	24,240	22,897	24,369	23,262	26,752	Aug-18	27,572
Hollywood		30,389	30,626	24,566	20,858	23,612	26,410	26,488	31,374	26,737	20,590	21,916	30,941	Feb-19	31,374
Hood River		28,890	29,619	21,418	20,147	25,772	26,161	26,041	29,769	32,032	19,828	19,026	25,614	Mar-19	32,032
Hornet		13,244	13,931	10,181	10,128	11,153	12,238	11,908	14,333	11,537	9,764	8,725	11,053	Feb-19	14,333
Independence		19,836	19,252	16,355	12,854	16,035	17,532	17,500	18,857	18,690	13,881	13,598	18,910	Jul-18	19,836
Jacksonville		16,673	15,108	11,541	9,019	13,017	14,531	14,721	15,478	13,614	10,131	9,097	14,748	Jul-18	16,673
Jefferson		10,938	10,555	8,595	7,258	10,062	11,544	11,105	12,066	12,000	8,564	7,964	11,087	Feb-19	12,066
Jerome Prairie		12,192	10,180	8,560	9,858	14,382	12,911	13,551	14,492	13,027	9,609	8,806	10,487	Feb-19	14,492
Junction City		7,972	7,895	8,365	6,762	8,874	9,513	8,981	8,872	8,996	7,092	6,242	7,777	Dec-18	9,513
Killingsworth		36,164	37,607	30,445	29,465	33,784	35,125	35,541	50,246	49,952	30,927	28,925	35,276	Feb-19	50,246
Knott		32,665	31,315	27,986	26,411	26,875	28,726	28,162	26,364	26,249	21,935	23,781	27,406	Jul-18	32,665
Lakeport		18,504	18,932	16,929	17,833	17,819	17,686	18,441	18,890	18,006	16,746	16,615	17,408	Aug-18	18,932
Lebanon		29,860	29,145	24,188	22,791	26,554	30,235	28,211	29,743	30,547	22,789	21,311	28,676	Mar-19	30,547
Lincoln		38,522	39,065	35,184	31,161	31,285	34,135	33,635	35,956	36,135	29,589	32,288	37,266	Aug-18	39,065
Lockhart		13,765	13,451	15,723	18,790	21,001	22,726	23,519	25,464	24,110	18,045	15,786	13,052	Feb-19	25,464
Lyons		17,504	17,276	16,947	17,916	19,130	19,056	20,292	21,233	21,803	17,904	17,716	16,223	Mar-19	21,803
Madras		16,075	17,077	12,567	14,008	17,227	18,289	17,042	22,854	19,839	14,321	11,894	14,891	Feb-19	22,854
Mallory		12,094	11,918	9,697	9,245	15,198	17,351	13,848	14,550	14,243	10,881	9,807	13,345	Dec-18	17,351
Marys River		15,828	15,790	14,146	14,947	16,642	18,022	17,337	17,934	17,252	12,811	13,390	14,973	Dec-18	18,022
Medford		26,138	24,895	22,434	16,896	19,761	18,891	19,301	23,814	21,439	18,084	22,712	24,178	Jul-18	26,138
Merlin		22,384	19,736	16,041	19,062	27,214	24,826	26,782	28,732	25,903	19,469	17,880	24,374	Feb-19	28,732
Merrill		8,048	6,802	5,507	4,125	3,927	3,922	3,857	4,305	3,726	3,952	6,602	7,929	Jul-18	8,048
Mile High		7,491	7,326	8,019	9,632	10,550	11,973	11,167	12,543	11,716	9,485	8,277	6,935	Feb-19	12,543
Murder Creek		47,758	46,657	45,361	41,880	47,464	47,756	47,141	50,326	47,791	45,448	46,018	55,928	Jun-19	55,928
Oak Knoll		18,095	16,991	13,735	12,911	15,745	18,551	18,719	19,987	17,481	13,877	11,817	16,315	Feb-19	19,987
O'Brien		1,136	1,006	881	1,206	1,447	1,389	1,441	1,692	1,434	1,234	1,166	967	Feb-19	1,692
Oremet		31,182	31,259	28,586	26,199	25,328	26,551	33,614	29,686	16,976	21,171	24,474	27,547	Jan-19	33,614
Overpass		37,265	39,573	29,144	30,492	33,833	38,413	34,846	37,914	38,941	31,281	28,648	33,269	Aug-18	39,573
Pallette		349	367	236	346	396	469	455	527	445	325	274	251	Feb-19	527
Park Street		31,260	27,707	23,506	19,132	24,224	24,486	26,037	26,056	24,586	19,432	21,823	28,758	Jul-18	31,260
Parkrose		25,988	27,267	22,862	20,336	24,494	26,308	27,416	30,433	24,338	18,302	19,681	26,542	Feb-19	30,433
Pilot Butte		16,542	12,000	11,834	11,826	13,367	15,857	13,922	15,990	15,684	11,600	10,419	13,473	Jul-18	16,542
Prineville		34,822	35,913	26,287	27,085	32,714	36,242	33,373	39,273	36,766	29,150	30,255	15,803	Feb-19	39,273
Queen Ave		35,172	34,387	27,780	22,824	27,278	30,171	30,080	31,834	30,349	24,108	24,770	35,756	Jun-19	35,756
Redmond		35,359	36,957	26,509	29,276	34,597	37,528	34,175	39,058	37,491	29,079	27,687	30,855	Feb-19	39,058
Riddle		12,004	11,965	10,156	12,261	13,752	14,253	14,108	14,134	13,361	11,487	11,714	12,013	Dec-18	14,253
Riddle Veneer		10,609	10,910	11,209	11,187	10,759	10,506	11,096	11,429	11,175	10,863	10,521	10,422	Feb-19	11,429
Roseburg		21,621	20,953	16,861	15,703	18,898	20,314	20,787	21,881	21,409	15,979	16,013	21,038	Feb-19	21,881
Roxy Ann		14,046	12,406	10,097	5,633	6,484	8,036	7,800	8,032	7,014	5,778	8,062	12,567	Jul-18	14,046
Russelville		28,788	28,596	24,089	20,427	25,177	28,277	28,415	30,072	28,230	21,038	20,598	27,399	Feb-19	30,072
Sage Road		31,505	30,771	27,908	21,898	22,330	24,635	24,666	28,340	18,428	21,339	24,177	29,651	Jul-18	31,505
Scenic		28,275	29,153	26,861	17,440	18,827	20,205	19,663	20,707	19,055	14,579	18,710	26,486	Aug-18	29,153
Scio		5,276	5,135	3,927	3,683	4,802	5,570	5,359	5,490	5,579	3,820	3,631	4,654	Mar-19	5,579
Seaside		14,294	13,431	13,681	15,589	18,005	20,264	19,474	20,541	19,482	16,046	15,997	12,794	Feb-19	20,541
Shevlin Park		21,340	23,050	14,869	15,514	16,340	18,947	17,067	19,353	19,076	14,063	12,673	15,658	Aug-18	23,050
Southgate		14,643	14,471	11,715	11,901	13,825	13,930	13,685	15,163	14,824	11,578	11,556	13,983	Feb-19	15,163
State Street		18,474	19,872	20,727	24,516	28,362	31,912	33,621	36,249	35,291	27,668	23,518	19,867	Feb-19	36,249
Stayton		41,459	40,756	31,454	28,217	32,373	36,109	34,209	36,134	35,093	26,610	24,477	33,510	Jul-18	41,459
Stevens Road		11,753	18,236	7,981	5,156	6,671	7,853	7,587	9,143	8,454	6,518	6,411	10,778	Aug-18	18,236
Sutherlin		11,352	10,893	8,617	9,259	10,880	12,036	11,559	15,009	16,004	9,106	8,276	10,862	Mar-19	16,004
Sweet Home		21,915	21,765	17,810	19,791	24,758	26,784	24,241	26,068	27,542	17,784	17,276	19,389	Mar-19	27,542
Takelma		8,475	8,023	6,477	6,847	9,072	9,659	10,466	10,411	9,381	6,489	5,433	7,449	Jan-19	10,466

Talent	22,167	20,674	16,690	13,737	19,668	21,258	21,573	23,329	20,055	14,999	13,071	19,752	Feb-19	23,329
Texum	12,220	11,153	10,582	11,155	11,322	12,356	12,584	14,260	12,124	10,304	10,069	12,497	Feb-19	14,260
Umatilla	12,655	12,356	10,352	8,832	10,191	10,621	21,630	11,624	12,178	7,701	9,547	12,068	Jan-19	21,630
Vernon	32,292	31,401	25,047	22,515	26,745	27,400	31,898	33,732	33,754	25,192	23,955	34,280	Jun-19	34,280
Vilas Road	18,601	15,327	13,849	12,001	13,105	14,642	15,010	15,273	14,071	11,740	11,850	14,528	Jul-18	18,601
Village Green	11,732	11,299	8,911	10,546	11,881	13,503	11,944	14,737	13,412	8,369	8,744	12,285	Feb-19	14,737
Vine Street	27,835	23,598	18,399	14,175	16,956	18,756	18,096	18,852	17,656	17,408	21,794	20,142	Jul-18	27,835
Warrenton	15,609	16,069	14,812	16,226	16,881	18,735	18,391	19,475	18,304	16,301	15,044	15,426	Feb-19	19,475
Weston	9,807	10,249	9,615	9,796	8,516	7,186	7,171	7,520	7,366	7,473	7,083	8,683	Aug-18	10,249
Westside	13,184	13,107	10,641	11,279	11,587	13,032	12,827	13,517	12,475	11,296	10,450	10,151	Feb-19	13,517
White City	44,342	41,959	38,994	36,398	37,384	37,666	38,643	39,411	37,069	33,896	33,374	40,246	Jul-18	44,342
Winchester	24,075	23,140	18,130	16,972	19,589	20,383	21,552	21,964	21,402	16,822	16,939	22,704	Jul-18	24,075
Yew Avenue	15,667	16,681	11,322	11,186	13,421	15,369	13,986	16,328	15,702	11,179	10,023	13,151	Aug-18	16,681
													Total	
Substation peaks	633,139	323,657	-	-	-	145,583	106,941	889,574	168,381	32,107	-	141,159	2,440,541	
Weighting Factor	25.94%	13.26%	0.00%	0.00%	0.00%	5.97%	4.38%	36.45%	6.90%	1.32%	0.00%	5.78%	100%	

PacifiCorp
Oregon Marginal Cost Study
Weighted Distribution Peaks
Tied to December 2021 Forecast

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
		Jul-18 16 15:00	Aug-18 9 15:00	Sep-18 6 17:00	Oct-18 15 08:00	Nov-18 8 08:00	Dec-18 6 09:00	Jan-19 2 09:00	Feb-19 7 08:00	Mar-19 11 08:00	Apr-19 16 08:00	May-19 9 17:00	Jun-19 11 16:00	Sum of 12 Wgt Dist peaks
	Del. Volt													
Res - Schedule 4	(sec)	257.0	131.7	-	-	-	76.4	55.7	446.2	84.0	11.7	-	59.5	1,122.2
GS - Schedule 23														
0-15 kW	(sec)	27.3	13.9	-	-	-	5.3	3.5	28.1	6.1	0.9	-	5.5	90.7
15+ kW	(sec)	26.9	13.6	-	-	-	5.6	4.4	31.0	6.0	1.0	-	5.7	94.2
Primary	(pri)	0.0	0.0	-	-	-	0.0	0.0	0.0	0.0	0.0	-	0.0	0.1
GS - Schedule 28														
0-50 kW	(sec)	20.2	11.1	-	-	-	4.3	3.1	22.0	4.4	0.8	-	4.4	70.2
51-100 kW	(sec)	34.6	17.2	-	-	-	6.8	4.5	34.8	7.5	1.5	-	7.1	114.0
100+ kW	(sec)	44.9	23.7	-	-	-	9.3	6.4	55.3	11.2	1.8	-	8.9	161.5
Primary	(pri)	1.0	0.6	-	-	-	0.3	0.2	1.6	0.4	0.1	-	0.2	4.4
GS - Schedule 30														
0-300 kW	(sec)	9.4	4.6	-	-	-	2.0	1.2	12.0	2.3	0.4	-	2.0	33.9
300+ kW	(sec)	44.1	23.3	-	-	-	10.4	6.5	59.0	10.8	2.0	-	8.7	164.9
Primary	(pri)	4.5	2.3	-	-	-	1.0	0.7	5.6	1.1	0.2	-	0.9	16.4
LPS - Schedule 48														
1 - 4 MW	(sec)	20.6	10.7	-	-	-	5.1	2.9	27.2	5.0	1.0	-	4.3	76.8
1 - 4 MW	(pri)	22.4	11.2	-	-	-	4.8	3.0	26.2	5.1	1.0	-	4.8	78.5
> 4 MW	(sec)	2.1	1.1	-	-	-	0.4	0.2	2.4	0.5	0.1	-	0.4	7.2
> 4 MW	(pri)	37.9	19.6	-	-	-	8.2	4.1	44.6	8.5	1.8	-	7.7	132.5
Trans	(trn)	32.2	17.0	-	-	-	6.1	4.6	39.3	7.5	1.5	-	6.9	115.0
Irrigation - Sch 41	(sec)	18.4	10.6	-	-	-	0.1	0.0	0.4	0.4	0.2	-	2.7	32.8
Customer-Owned Lighting - Sch 53		-	-	-	-	-	-	0.0	0.3	-	-	-	-	0.3
Rec Field Lighting - Sch 54		0.0	0.0	-	-	-	0.0	0.0	0.0	0.0	0.0	-	0.0	0.0

PacifiCorp
Oregon Marginal Cost Study
Distribution Peaks @ Sales - MW
Tied to December 2021 Forecast

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		Jul-18 16 15:00	Aug-18 9 15:00	Sep-18 6 17:00	Oct-18 15 08:00	Nov-18 8 08:00	Dec-18 6 09:00	Jan-19 2 09:00	Feb-19 7 08:00	Mar-19 11 08:00	Apr-19 16 08:00	May-19 9 17:00	Jun-19 11 16:00
	Del. Volt												
Res - Schedule 4	(sec)	990.6	993.4	924.6	806.3	1,179.8	1,280.3	1,270.4	1,224.1	1,217.2	890.9	899.9	1,029.4
GS - Schedule 23													
0-15 kW	(sec)	105.3	105.0	89.6	68.0	67.3	88.2	79.8	77.0	88.9	72.0	76.3	95.6
15+ kW	(sec)	103.6	102.8	88.6	74.2	78.2	93.3	99.5	85.1	87.1	78.7	78.0	97.9
Primary	(pri)	0.1	0.0	0.0	0.1	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1
GS - Schedule 28													
0-50 kW	(sec)	77.9	83.6	69.5	57.0	54.4	72.8	69.9	60.2	64.1	57.7	63.1	75.6
51-100 kW	(sec)	133.6	129.5	100.9	100.1	91.4	113.5	103.6	95.5	108.7	111.7	91.4	122.4
100+ kW	(sec)	172.9	178.7	139.5	135.8	134.4	155.3	147.0	151.7	162.7	138.3	126.6	154.2
Primary	(pri)	3.9	4.5	4.0	5.2	3.4	5.0	4.7	4.5	5.5	4.5	2.8	3.5
GS - Schedule 30													
0-300 kW	(sec)	36.4	34.7	27.4	30.2	31.0	33.7	27.9	33.0	32.7	28.0	27.6	34.7
300+ kW	(sec)	169.9	176.0	147.2	152.1	162.3	174.5	148.4	162.0	157.0	152.0	139.9	150.9
Primary	(pri)	17.5	17.3	14.5	17.1	18.0	16.6	15.9	15.4	15.7	15.9	13.1	16.0
LPS - Schedule 48													
1 - 4 MW	(sec)	79.4	80.7	72.4	74.8	78.6	85.0	66.9	74.6	72.9	77.7	66.6	73.8
1 - 4 MW	(pri)	86.4	84.2	78.5	80.6	82.6	81.2	69.1	71.8	73.8	78.0	67.4	82.8
> 4 MW	(sec)	7.9	8.0	7.9	7.2	7.4	7.5	5.1	6.7	6.7	7.3	7.5	7.3
> 4 MW	(pri)	146.0	148.0	144.9	131.8	136.0	137.9	93.9	122.4	123.8	134.6	137.4	133.8
Trans	(trn)	124.2	128.0	121.7	117.9	92.8	101.5	103.9	107.9	108.1	114.6	108.7	119.9
Irrigation - Sch 41	(sec)	71.0	80.1	63.3	14.0	3.0	1.0	1.0	1.1	5.3	11.6	40.2	47.2
Customer-Owned Lighting - Sch 53		-	-	-	-	0.1	-	0.0	0.7	-	-	-	-
Rec Field Lighting - Sch 54		0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0

Cust Data 6

PacifiCorp
Oregon Marginal Cost Study
Allocation of Uncollectible Expense between Members of Class
12 Months Ended December 2021

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			Revenues December 2021		Percent of Total Revenues		Allocated Net Uncollectible		
Line	Description	Del. Volt	Commercial	Industrial	Commercial	Industrial	Commercial	Industrial	Total
1	Res - Sch 4	(sec)	-	-	0.00%	0.00%	$0	$0	$1,601,950
2									
3	GS - Sch 23	(sec)	$123,900,873	$1,962,522	24.25%	1.55%	$69,126	$95	$69,221
4	GS - Sch 23	(pri)	$200,615	$16,818	0.04%	0.01%	$112	$1	$113
5	GS - Sch 23	Total	$124,101,488	$1,979,340	24.29%	1.57%	$69,238	$96	$69,333
6									
7	GS - Sch 28	(sec)	$176,068,058	$8,353,235	34.46%	6.61%	$98,230	$404	$98,634
8	GS - Sch 28	(pri)	$1,742,096	$518,861	0.34%	0.41%	$972	$25	$997
9	GS - Sch 28	Total	$177,810,154	$8,872,096	34.80%	7.02%	$99,202	$429	$99,631
10									
11	GS - Sch 30	(sec)	$87,792,802	$15,080,828	17.18%	11.93%	$48,981	$729	$49,710
12	GS - Sch 30	(pri)	$6,516,781	$1,421,741	1.28%	1.12%	$3,636	$69	$3,705
13	GS - Sch 30	Total	$94,309,583	$16,502,569	18.46%	13.05%	$52,616	$798	$53,414
14									
15	LPS - Sch 48	(sec)	$25,453,322	$18,074,472	4.98%	14.30%	$14,201	$874	$15,074
16	LPS - Sch 48	(pri)	$30,807,675	$78,010,673	6.03%	61.71%	$17,188	$3,771	$20,959
17	LPS - Sch 48	(trn)	$58,479,439	$2,978,163	11.44%	2.36%	$32,626	$144	$32,770
18	LPS - Sch 48	Total	$114,740,436	$99,063,308	22.46%	78.36%	$64,015	$4,788	$68,803
19									
20	Irg - Sch 41	(sec)	-	$25,947,111	0.00%	100.00%	$0	$35,721	$35,721
21			-	$25,947,111	0.00%	100.00%	$0	$35,721	$35,721
22									
23	Total		$510,961,661	$152,364,424			$285,072	$41,832	$1,928,854

12 Months Ended June 2019 Net Write-offs	
Residential	$1,601,950
Commercial	$285,072
Industrial	$6,111
Irrigation	$35,721
Total	1,928,854

Docket No. UE 374
Exhibit PAC/1409
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Target Functionalized Revenues and Billing Determinants

February 2020

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues
Forecast 12 Months Ended December 31, 2021

Rate Schedule		Present Revenues ($000)	Cost of Service Revenues ($000)	Revenue Neutral Rate Spread Adj. Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
Schedule 4, Residential						
	Transmission & Ancillary Services[1]	$26,115	$45,301		$45,301	$45,273
	System Usage- Schedule 200 Related	$3,975	$4,657		$4,657	$4,638
	System Usage- T&A and Schedule 201 Related	$4,196	$4,260		$4,260	$4,251
	Distribution	$257,712	$281,910	-$2,500	$279,410	$279,468
	Other Adjustments	$13,469	$0		$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$176,026	$187,809		$187,809	$187,784
	Generation Energy - Net Power Costs (Sch 201)	$147,025	$126,530		$147,025	$147,025
	Total	$628,518	$650,467	-$2,500	$668,462	$668,438
Schedule 23, Small General Service						
	Transmission & Ancillary Services[1]	$5,097	$8,197		$8,197	$8,193
	System Usage- Schedule 200 Related	$791	$882		$882	$881
	System Usage- T&A and Schedule 201 Related	$825	$793		$793	$791
	Distribution	$51,200	$62,720	$1,773	$64,493	$64,498
	Other Adjustments	$3,511	$0		$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$35,831	$36,433		$36,433	$36,437
	Generation Energy - Net Power Costs (Sch 201)	$28,827	$24,545		$28,827	$28,827
	Total	$126,081	$133,571	$1,773	$139,625	$139,627
Schedule 28, General Service 31-200kW						
Secondary Voltage						
	Transmission & Ancillary Services[1]	$10,037	$14,882		$14,882	$14,888
	System Usage- Schedule 200 Related	$1,510	$1,730		$1,730	$1,731
	System Usage- T&A and Schedule 201 Related	$1,570	$1,560		$1,560	$1,550
	Distribution	$45,939	$51,235	$1,448	$52,683	$52,713
	Other Adjustments	$6,491	$0		$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$65,991	$65,418		$65,418	$65,415
	Generation Energy - Net Power Costs (Sch 201)	$52,883	$44,073		$52,883	$52,883
	Total	$184,421	$178,897	$1,448	$189,155	$189,179
Primary Voltage						
	Transmission & Ancillary Services[1]	$108	$189		$189	$188
	System Usage- Schedule 200 Related	$18	$21		$21	$21
	System Usage- T&A and Schedule 201 Related	$19	$19		$19	$19
	Distribution	$591	$687	$19	$707	$707
	Other Adjustments	$79	$0		$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$794	$824		$824	$824
	Generation Energy - Net Power Costs (Sch 201)	$652	$555		$652	$652
	Total	$2,261	$2,295	$19	$2,411	$2,411
Schedule 30, General Service 201-999kW						
Secondary Voltage						
	Transmission & Ancillary Services[1]	$5,960	$8,798		$8,798	$8,783
	System Usage- Schedule 200 Related	$847	$1,042		$1,042	$1,036
	System Usage- T&A and Schedule 201 Related	$885	$931		$931	$935
	Distribution	$20,912	$23,696	$670	$24,365	$24,393
	Other Adjustments	$3,965	$0		$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$38,591	$40,053		$40,053	$40,044
	Generation Energy - Net Power Costs (Sch 201)	$31,714	$26,984		$31,714	$31,714
	Total	$102,874	$101,503	$670	$106,903	$106,906
Primary Voltage						
	Transmission & Ancillary Services[1]	$475	$712		$712	$711
	System Usage- Schedule 200 Related	$64	$79		$79	$79
	System Usage- T&A and Schedule 201 Related	$66	$72		$72	$71
	Distribution	$1,670	$1,912	$54	$1,966	$1,968
	Other Adjustments	$304	$0		$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$2,946	$3,105		$3,105	$3,102
	Generation Energy - Net Power Costs (Sch 201)	$2,414	$2,092		$2,414	$2,414
	Total	$7,939	$7,971	$54	$8,348	$8,347
Schedule 41, Agricultural Pumping Service						
	Transmission & Ancillary Services[1]	$811	$1,429		$1,429	$1,429
	System Usage- Schedule 200 Related	$164	$148		$148	$164
	System Usage- T&A and Schedule 201 Related	$168	$168		$168	$213
	Distribution	$11,330	$13,892	$393	$14,285	$14,227
	Other Adjustments	$709	$0		$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$7,030	$6,811		$6,811	$6,811
	Generation Energy - Net Power Costs (Sch 201)	$5,736	$4,588		$5,736	$5,736
	Total	$25,947	$27,036	$393	$28,576	$28,579

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues
Forecast 12 Months Ended December 31, 2021

Rate Schedule	Present Revenues ($000)	Cost of Service Revenues ($000)	Revenue Neutral Rate Spread Adj. Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1) (2)	(3)	(4)	(5)	(6)	(7)
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
Transmission & Ancillary Services[1]	$2,546	$3,868		$3,868	$3,867
System Usage- Schedule 200 Related	$372	$424		$424	$422
System Usage- T&A and Schedule 201 Related	$383	$378		$378	$378
Distribution	$7,986	$12,288	-$115	$12,173	$12,149
Other Adjustments	$1,662	$0		$0	$0
Generation Energy - Other (non-NPC) (Sch 200)	$16,819	$17,602		$17,602	$17,624
Generation Energy - Net Power Costs (Sch 201)	$13,759	$11,859		$13,759	$13,759
Total	$43,528	$46,418	-$115	$48,204	$48,198
Primary Voltage					
Transmission & Ancillary Services[1]	$6,500	$9,729		$9,729	$9,724
System Usage- Schedule 200 Related	$942	$1,156		$1,156	$1,158
System Usage- T&A and Schedule 201 Related	$1,266	$1,022		$1,022	$1,019
Distribution	$16,526	$22,389	-$507	$21,882	$21,935
Other Adjustments	$4,472	$0		$0	$0
Generation Energy - Other (non-NPC) (Sch 200)	$43,655	$46,212		$46,212	$46,168
Generation Energy - Net Power Costs (Sch 201)	$35,458	$31,134		$35,458	$35,458
Total	$108,818	$111,642	-$507	$115,460	$115,463
Transmission Voltage					
Transmission & Ancillary Services[1]	$3,375	$5,451		$5,451	$5,451
System Usage- Schedule 200 Related	$559	$714		$714	$716
System Usage- T&A and Schedule 201 Related	$598	$622		$622	$618
Distribution	$7,433	$8,007	-$944	$7,064	$7,067
Other Adjustments	$2,734	$0		$0	$0
Generation Energy - Other (non-NPC) (Sch 200)	$25,624	$27,605		$27,605	$27,600
Generation Energy - Net Power Costs (Sch 201)	$21,134	$18,598		$21,134	$21,134
Total	$61,458	$60,998	-$944	$62,590	$62,587
Schedules 15, 51, 53, 54 Lighting					
Secondary Voltage					
Transmission & Ancillary Services[1]	$31	$26		$26	$26
System Usage- Schedule 200 Related	$19	$13		$13	$13
System Usage- T&A and Schedule 201 Related	$20	$10		$10	$10
Distribution	$3,361	$3,765	$106	$3,871	$3,871
Other Adjustments	$99	$0		$0	$0
Generation Energy - Other (non-NPC) (Sch 200)	$931	$454		$454	$454
Generation Energy - Net Power Costs (Sch 201)	$779	$306		$779	$779
Total	$5,242	$4,573	$106	$5,153	$5,153
TOTAL	**$1,297,086**	**$1,325,372**	$399	**$1,374,888**	**$1,374,888**
Employee Discount	-$392		$2	-$417	-$417
Additional Rate Schedules					
Schedule 47	$5,249		($126)	$5,571	$5,571
Schedule 848	$2,222		($275)	$2,116	$2,116
Total Oregon	**$1,304,165**		**$0**	**$1,382,158**	**$1,382,158**
		Revenue Increase	**$0**	**$77,993**	**$77,993**

[1]Includes only FERC transmission plus ancillary services revenues. Non-FERC transmission revenues are recovered through distribution charges.

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2019
Forecast 12 Months Ended December 31, 2021

Schedule	Actual 7/18-6/19 Units	Normalized 7/18-6/19 Units	Forecast 1/21 - 12/21 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 4								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	5,480,370,435	5,483,040,703	5,521,126,670	kWh	0.473 ¢	$26,114,929	0.820 ¢	$45,273,239
System Usage Charge								
Sch 200 related, per kWh	5,480,370,435	5,483,040,703	5,521,126,670	kWh	0.072 ¢	$3,975,211	0.084 ¢	$4,637,746
T&A and Sch 201 related, per kWh	5,480,370,435	5,483,040,703	5,521,126,670	kWh	0.076 ¢	$4,196,056	0.077 ¢	$4,251,268
Distribution Charge								
Basic Charge Single Family, per month	4,861,272	4,861,272	4,984,042	bill	$9.50	$47,348,399	$12.00	$59,808,504
Basic Charge Multi Family, per month	1,198,574	1,198,574	1,228,844	bill	$9.50	$11,674,018	$7.00	$8,601,908
Total Bills	6,059,846	6,059,846	6,212,885	bill				
Three Phase Demand Charge, per kW demand	15,458	15,458	15,565	kW	$2.20	$34,243	$2.20	$34,243
Three Phase Minimum Demand Charge, per month	1,407	1,407	1,443	bill	$3.80	$5,483	$3.80	$5,483
Distribution Energy Charge, per kWh	5,480,370,435	5,483,040,703	5,521,126,670	kWh	3.598 ¢	$198,650,138	3.822 ¢	$211,017,461
Energy Charge - Schedule 200								
First Block kWh (0-1,000)	4,141,167,255	4,143,186,255	4,171,965,406	kWh	2.927 ¢	$122,113,427	3.279 ¢	$136,798,746
Second Block kWh (> 1,000)	1,339,203,180	1,339,854,448	1,349,161,264	kWh	3.996 ¢	$53,912,484	3.779 ¢	$50,984,804
Subtotal	5,480,370,435	5,483,040,703	5,521,126,670	kWh		$468,024,388		$521,413,402
Renewable Adjustment Clause (202), per kWh	5,480,370,435	5,483,040,703	5,521,126,670	kWh	0.075 ¢	$4,140,845	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	5,480,370,435	5,483,040,703	5,521,126,670	kWh	-0.022 ¢	($1,214,648)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	5,480,370,435	5,483,040,703	5,521,126,670	kWh	0.170 ¢	$9,385,915	0.000 ¢	$0
TAM Adj for Other Revs (205)								
First Block kWh (0-1,000)	4,141,167,255	4,143,186,255	4,171,965,406	kWh	0.019 ¢	$792,673	0.000 ¢	$0
Second Block kWh (> 1,000)	1,339,203,180	1,339,854,448	1,349,161,264	kWh	0.027 ¢	$364,274	0.000 ¢	$0
Subtotal						$481,493,447		$521,413,402
Schedule 201								
First Block kWh (0-1,000)	4,141,167,255	4,143,186,255	4,171,965,406	kWh	2.444 ¢	$101,962,835	2.444 ¢	$101,962,835
Second Block kWh (> 1,000)	1,339,203,180	1,339,854,448	1,349,161,264	kWh	3.340 ¢	$45,061,986	3.340 ¢	$45,061,986
Total	5,480,370,435	5,483,040,703	5,521,126,670	kWh		$628,518,268		$668,438,223
							Change	$39,919,955
Schedule No. 4 (Employee Discount)								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	13,836,916	13,836,916	13,933,029	kWh	0.473 ¢	$65,903	0.820 ¢	$114,251
System Usage Charge								
Sch 200 related, per kWh	13,836,916	13,836,916	13,933,029	kWh	0.072 ¢	$10,032	0.084 ¢	$11,704
T&A and Sch 201 related, per kWh	13,836,916	13,836,916	13,933,029	kWh	0.076 ¢	$10,589	0.077 ¢	$10,728
Distribution Charge								
Basic Charge Single Family, per month	11,570	11,570	11,862	bill	$9.50	$112,689	$12.00	$142,344
Basic Charge Multi Family, per month	558	558	572	bill	$9.50	$5,434	$7.00	$4,004
Total Bills	12,128	12,128	12,434	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	13,836,916	13,836,916	13,933,029	kWh	3.598 ¢	$501,310	3.822 ¢	$532,520
Energy Charge - Schedule 200								
First Block kWh (0-1,000)	9,779,065	9,779,065	9,846,992	kWh	2.927 ¢	$288,221	3.279 ¢	$322,883
Second Block kWh (> 1,000)	4,057,851	4,057,851	4,086,037	kWh	3.996 ¢	$163,278	3.779 ¢	$154,411
Subtotal	13,836,916	13,836,916	13,933,029	kWh		$1,157,456		$1,292,845
Renewable Adjustment Clause (202), per kWh	13,836,916	13,836,916	13,933,029	kWh	0.075 ¢	$10,450	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	13,836,916	13,836,916	13,933,029	kWh	-0.022 ¢	($3,065)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	13,836,916	13,836,916	13,933,029	kWh	0.170 ¢	$23,686	0.000 ¢	$0
TAM Adj for Other Revs (205)								
First Block kWh (0-1,000)	9,779,065	9,779,065	9,846,992	kWh	0.019 ¢	$1,871	0.000 ¢	$0
Second Block kWh (> 1,000)	4,057,851	4,057,851	4,086,037	kWh	0.027 ¢	$1,103	0.000 ¢	$0
Subtotal						$1,191,501		$1,292,845
Schedule 201								
First Block kWh (0-1,000)	9,779,065	9,779,065	9,846,992	kWh	2.444 ¢	$240,660	2.444 ¢	$240,660
Second Block kWh (> 1,000)	4,057,851	4,057,851	4,086,037	kWh	3.340 ¢	$136,474	3.340 ¢	$136,474
Total	13,836,916	13,836,916	13,933,029	kWh		$1,568,635		$1,669,979
Schedule 201 Employee Discount						($94,284)		($94,284)
Total Employee Discount						($392,159)		($417,495)
							Change	($25,336)

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2019
Forecast 12 Months Ended December 31, 2021

Schedule	Actual 7/18-6/19 Units	Normalized 7/18-6/19 Units	Forecast 1/21 - 12/21 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 23/723 - Composite General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	1,195,401,175	1,190,951,686	1,128,061,189	kWh	0.451 ¢	$5,087,556	0.725 ¢	$8,178,444
System Usage Charge								
Sch 200 related, per kWh	1,195,401,175	1,190,951,686	1,128,061,189	kWh	0.070 ¢	$789,643	0.078 ¢	$879,888
T&A and Sch 201 related, per kWh	1,195,401,175	1,190,951,686	1,128,061,189	kWh	0.073 ¢	$823,485	0.070 ¢	$789,643
Distribution Charge								
Basic Charge								
Single Phase, per month	762,124	762,124	762,309	bill	$17.35	$13,226,061	$17.35	$13,226,061
Three Phase, per month	231,884	231,884	231,815	bill	$25.90	$6,004,009	$25.90	$6,004,009
Load Size Charge								
≤ 15 kW					No Charge		No Charge	
per kW for all kW in excess of 15 kW	1,034,889	1,034,889	978,378	kW	$1.20	$1,174,054	$1.50	$1,467,567
Demand Charge, the first 15 kW of demand					No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	529,489	529,489	500,681	kW	$4.03	$2,017,744	$5.08	$2,543,459
Reactive Power Charge, per kvar	134,061	134,061	126,845	kvar	65.00 ¢	$82,449	65.00 ¢	$82,449
Distribution Energy Charge, per kWh	1,195,401,175	1,190,951,686	1,128,061,189	kWh	2.536 ¢	$28,607,632	3.640 ¢	$41,061,427
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	926,888,169	923,507,169	875,459,662	kWh	3.365 ¢	$29,459,218	3.422 ¢	$29,958,230
All additional kWh, per kWh	268,513,006	267,444,517	252,601,527	kWh	2.498 ¢	$6,309,986	2.540 ¢	$6,416,079
Subtotal	1,195,401,175	1,190,951,686	1,128,061,189	kWh		$93,581,837		$110,607,256
Renewable Adjustment Clause (202), per kWh	1,195,401,175	1,190,951,686	1,128,061,189	kWh	0.142 ¢	$1,601,847	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	1,195,401,175	1,190,951,686	1,128,061,189	kWh	-0.021 ¢	($236,893)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	1,195,401,175	1,190,951,686	1,128,061,189	kWh	0.168 ¢	$1,895,143	0.000 ¢	$0
TAM Adj for Other Revs (205)								
1st 3,000 kWh, per kWh	926,888,169	923,507,169	875,459,662	kWh	0.023 ¢	$201,356	0.000 ¢	$0
All additional kWh, per kWh	268,513,006	267,444,517	252,601,527	kWh	0.017 ¢	$42,942	0.000 ¢	$0
Subtotal						$97,086,232		$110,607,256
Schedule 201								
1st 3,000 kWh, per kWh	926,888,169	923,507,169	875,459,662	kWh	2.708 ¢	$23,707,448	2.708 ¢	$23,707,448
All additional kWh, per kWh	268,513,006	267,444,517	252,601,527	kWh	2.007 ¢	$5,069,713	2.007 ¢	$5,069,713
Total	1,195,401,175	1,190,951,686	1,128,061,189	kWh		$125,863,393		$139,384,417
							Change	$13,521,024

Schedule	Actual 7/18-6/19 Units	Normalized 7/18-6/19 Units	Forecast 1/21 - 12/21 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 23/723 - Composite General Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	2,206,555	2,206,555	2,086,241	kWh	0.438 ¢	$9,138	0.705 ¢	$14,708
System Usage Charge								
Sch 200 related, per kWh	2,206,555	2,206,555	2,086,241	kWh	0.068 ¢	$1,419	0.076 ¢	$1,586
T&A and Sch 201 related, per kWh	2,206,555	2,206,555	2,086,241	kWh	0.071 ¢	$1,481	0.068 ¢	$1,419
Distribution Charge								
Basic Charge								
Single Phase, per month	520	520	522	bill	$17.35	$9,057	$17.35	$9,057
Three Phase, per month	563	563	562	bill	$25.90	$14,556	$25.90	$14,556
Load Size Charge								
≤ 15 kW					No Charge		No Charge	
per kW for all kW in excess of 15 kW	4,531	4,531	4,279	kW	$1.20	$5,135	$1.50	$6,419
Demand Charge, the first 15 kW of demand					No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	1,591	1,591	1,506	kW	$3.92	$5,904	$4.94	$7,440
Reactive Power Charge, per kvar	2,678	2,678	2,538	kvar	60.00 ¢	$1,523	60.00 ¢	$1,523
Distribution Energy Charge, per kWh	2,206,555	2,206,555	2,086,241	kWh	2.465 ¢	$51,426	3.537 ¢	$73,790
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	1,406,596	1,406,596	1,329,489	kWh	3.271 ¢	$43,488	3.326 ¢	$44,219
All additional kWh, per kWh	799,959	799,959	756,752	kWh	2.427 ¢	$18,366	2.468 ¢	$18,677
Subtotal	2,206,555	2,206,555	2,086,241	kWh		$161,493		$193,394
Renewable Adjustment Clause (202), per kWh	2,206,555	2,206,555	2,086,241	kWh	0.142 ¢	$2,962	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	2,206,555	2,206,555	2,086,241	kWh	-0.021 ¢	($438)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	2,206,555	2,206,555	2,086,241	kWh	0.163 ¢	$3,401	0.000 ¢	$0
TAM Adj for Other Revs (205)								
1st 3,000 kWh, per kWh	1,406,596	1,406,596	1,329,489	kWh	0.022 ¢	$292	0.000 ¢	$0
All additional kWh, per kWh	799,959	799,959	756,752	kWh	0.016 ¢	$121	0.000 ¢	$0
Subtotal						$167,831		$193,394
Schedule 201								
1st 3,000 kWh, per kWh	1,406,596	1,406,596	1,329,489	kWh	2.623 ¢	$34,872	2.623 ¢	$34,872
All additional kWh, per kWh	799,959	799,959	756,752	kWh	1.946 ¢	$14,726	1.946 ¢	$14,726
Total	2,206,555	2,206,555	2,086,241	kWh		$217,429		$242,992
							Change	$25,563

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2019
Forecast 12 Months Ended December 31, 2021

Schedule	Actual 7/18-6/19 Units	Normalized 7/18-6/19 Units	Forecast 1/21 - 12/21 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 28/728 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	6,884,240	6,884,240	6,736,476	kW	$1.49	$10,037,349	$2.21	$14,887,612
System Usage Charge								
Sch 200 related, per kWh	2,065,326,161	2,056,978,440	2,012,760,391	kWh	0.075 ¢	$1,509,570	0.086 ¢	$1,730,974
T&A and Sch 201 related, per kWh	2,065,326,161	2,056,978,440	2,012,760,391	kWh	0.078 ¢	$1,569,953	0.077 ¢	$1,549,826
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	56,622	56,622	58,196	bill	$18.00	$1,047,528	$21.00	$1,222,116
Load Size 51-100 kW, per month	42,460	42,460	43,636	bill	$34.00	$1,483,624	$39.00	$1,701,804
Load Size 101-300 kW, per month	22,898	22,898	23,519	bill	$81.00	$1,905,039	$93.00	$2,187,267
Load Size > 300 kW, per month	494	494	508	bill	$115.00	$58,420	$132.00	$67,056
Load Size Charge								
≤ 50 kW, per kW	2,193,232	2,193,232	2,145,627	kW	$1.15	$2,467,471	$1.30	$2,789,315
51-100 kW, per kW	2,969,956	2,969,956	2,905,043	kW	$0.90	$2,614,539	$1.05	$3,050,295
101-300 kW, per kW	3,437,575	3,437,575	3,365,420	kW	$0.55	$1,850,981	$0.65	$2,187,523
>300 kW, per kW	196,567	196,567	191,937	kW	$0.35	$67,178	$0.40	$76,775
Demand Charge, per kW	6,884,240	6,884,240	6,736,476	kW	$3.88	$26,137,527	$4.45	$29,977,318
Reactive Power Charge, per kvar	622,277	622,277	609,823	kvar	65.00 ¢	$396,385	65.00 ¢	$396,385
Distribution Energy Charge, per kWh	2,065,326,161	2,056,978,440	2,012,760,391	kWh	0.393 ¢	$7,910,148	0.450 ¢	$9,057,422
Energy Charge - Schedule 200								
1st 20,000 kWh, per kWh	1,470,545,848	1,464,579,848	1,432,810,369	kWh	3.304 ¢	$47,340,055	3.250 ¢	$46,566,337
All additional kWh, per kWh	594,780,313	592,398,592	579,950,022	kWh	3.216 ¢	$18,651,193	3.250 ¢	$18,848,376
Subtotal	2,065,326,161	2,056,978,440	2,012,760,391	kWh		$125,046,960		$136,296,401
Renewable Adjustment Clause (202), per kWh	2,065,326,161	2,056,978,440	2,012,760,391	kWh	0.152 ¢	$3,059,396	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	2,065,326,161	2,056,978,440	2,012,760,391	kWh	-0.022 ¢	($442,807)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	2,065,326,161	2,056,978,440	2,012,760,391	kWh	0.058 ¢	$1,167,401	0.000 ¢	$0
, per kW	6,884,240	6,884,240	6,736,476	kW	$0.34	$2,290,402	$0.00	$0
TAM Adj for Other Revs (205)								
1st 20,000 kWh, per kWh	1,470,545,848	1,464,579,848	1,432,810,369	kWh	0.021 ¢	$300,890	0.000 ¢	$0
All additional kWh, per kWh	594,780,313	592,398,592	579,950,022	kWh	0.020 ¢	$115,990	0.000 ¢	$0
Subtotal						$131,538,232		$136,296,401
Schedule 201								
1st 20,000 kWh, per kWh	1,470,545,848	1,464,579,848	1,432,810,369	kWh	2.649 ¢	$37,955,147	2.649 ¢	$37,955,147
All additional kWh, per kWh	594,780,313	592,398,592	579,950,022	kWh	2.574 ¢	$14,927,914	2.574 ¢	$14,927,914
Total	2,065,326,161	2,056,978,440	2,012,760,391	kWh		$184,421,293		$189,179,462
							Change	$4,758,169
Schedule No. 28/728 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	90,920	90,920	89,302	kW	$1.21	$108,055	$2.11	$188,427
System Usage Charge								
Sch 200 related, per kWh	26,482,790	26,482,790	25,965,347	kWh	0.069 ¢	$17,916	0.080 ¢	$20,772
T&A and Sch 201 related, per kWh	26,482,790	26,482,790	25,965,347	kWh	0.072 ¢	$18,695	0.072 ¢	$18,695
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	186	186	191	bill	$24.00	$4,584	$29.00	$5,539
Load Size 51-100 kW, per month	228	228	233	bill	$41.00	$9,553	$49.00	$11,417
Load Size 101-300 kW, per month	374	374	382	bill	$96.00	$36,672	$115.00	$43,930
Load Size > 300 kW, per month	66	66	67	bill	$137.00	$9,179	$164.00	$10,988
Load Size Charge								
≤ 50 kW, per kW	7,199	7,199	7,034	kW	$1.35	$9,496	$1.60	$11,254
51-100 kW, per kW	16,834	16,834	16,544	kW	$1.10	$18,198	$1.30	$21,507
101-300 kW, per kW	66,524	66,524	65,374	kW	$0.65	$42,493	$0.80	$52,299
>300 kW, per kW	38,790	38,790	38,115	kW	$0.35	$13,340	$0.40	$15,246
Demand Charge, per kW	90,920	90,920	89,302	kW	$4.70	$419,719	$5.62	$501,877
Reactive Power Charge, per kvar	17,349	17,349	17,121	kvar	60.00 ¢	$10,273	60.00 ¢	$10,273
Distribution Energy Charge, per kWh	26,482,790	26,482,790	25,965,347	kWh	0.068 ¢	$17,656	0.089 ¢	$23,109
Energy Charge - Schedule 200								
1st 20,000 kWh, per kWh	11,054,203	11,054,203	10,852,496	kWh	3.108 ¢	$337,296	3.174 ¢	$344,458
All additional kWh, per kWh	15,428,587	15,428,587	15,112,851	kWh	3.024 ¢	$457,013	3.174 ¢	$479,682
Subtotal	26,482,790	26,482,790	25,965,347	kWh		$1,530,138		$1,759,473
Renewable Adjustment Clause (202), per kWh	26,482,790	26,482,790	25,965,347	kWh	0.152 ¢	$39,467	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	26,482,790	26,482,790	25,965,347	kWh	-0.022 ¢	($5,712)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	26,482,790	26,482,790	25,965,347	kWh	0.055 ¢	$14,281	0.000 ¢	$0
, per kW	90,920	90,920	89,302	kW	$0.29	$25,898	$0.00	$0
TAM Adj for Other Revs (205)								
1st 20,000 kWh, per kWh	11,054,203	11,054,203	10,852,496	kWh	0.021 ¢	$2,279	0.000 ¢	$0
All additional kWh, per kWh	15,428,587	15,428,587	15,112,851	kWh	0.020 ¢	$3,023	0.000 ¢	$0
Subtotal						$1,609,374		$1,759,473
Schedule 201								
1st 20,000 kWh, per kWh	11,054,203	11,054,203	10,852,496	kWh	2.549 ¢	$276,630	2.549 ¢	$276,630
All additional kWh, per kWh	15,428,587	15,428,587	15,112,851	kWh	2.481 ¢	$374,950	2.481 ¢	$374,950
Total	26,482,790	26,482,790	25,965,347	kWh		$2,260,954		$2,411,053
							Change	$150,099

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2019
Forecast 12 Months Ended December 31, 2021

Schedule	Actual 7/18-6/19 Units	Normalized 7/18-6/19 Units	Forecast 1/21 - 12/21 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 30/730 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	3,479,203	3,479,203	3,485,385	kW	$1.71	$5,960,008	$2.52	$8,783,170
System Usage Charge								
Sch 200 related, per kWh	1,265,586,379	1,260,641,152	1,263,679,782	kWh	0.067 ¢	$846,665	0.082 ¢	$1,036,217
T&A and Sch 201 related, per kWh	1,265,586,379	1,260,641,152	1,263,679,782	kWh	0.070 ¢	$884,576	0.074 ¢	$935,123
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	128	128	131	bill	$468.00	$61,308	$541.00	$70,871
Load Size 201-300 kW, per month	2,710	2,710	2,777	bill	$138.00	$383,226	$161.00	$447,097
Load Size > 300 kW, per month	6,815	6,815	6,980	bill	$363.00	$2,533,740	$423.00	$2,952,540
Load Size Charge								
≤ 200 Kw, per kW					No Charge	$0	No Charge	$0
201-300 kW, per kW	706,821	706,821	708,467	kW	$1.65	$1,168,971	$1.90	$1,346,087
>300 kW, per kW	3,400,179	3,400,179	3,406,483	kW	$0.80	$2,725,186	$0.95	$3,236,159
Demand Charge, per kW	3,479,203	3,479,203	3,485,385	kW	$3.98	$13,871,832	$4.64	$16,172,186
Reactive Power Charge, per kvar	260,666	260,666	258,668	kvar	65.00 ¢	$168,134	65.00 ¢	$168,134
Energy Charge - Schedule 200								
Demand Charge, per kW	3,479,203	3,479,203	3,485,385	kW	$1.88	$6,542,068	$1.95	$6,796,501
1st 20,000 kWh, per kWh	186,966,147	186,253,147	186,649,079	kWh	2.860 ¢	$5,338,164	2.631 ¢	$4,910,737
All additional kWh, per kWh	1,078,620,232	1,074,388,005	1,077,030,703	kWh	2.480 ¢	$26,710,361	2.631 ¢	$28,336,678
Subtotal	1,265,586,379	1,260,641,152	1,263,679,782	kWh		$67,194,239		$75,191,500
Renewable Adjustment Clause (202), per kWh	1,265,586,379	1,260,641,152	1,263,679,782	kWh	0.149 ¢	$1,882,883	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	1,265,586,379	1,260,641,152	1,263,679,782	kWh	-0.021 ¢	($265,373)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	1,265,586,379	1,260,641,152	1,263,679,782	kWh	0.055 ¢	$695,024	0.000 ¢	$0
, per kW	3,479,203	3,479,203	3,485,385	kW	$0.40	$1,394,154	$0.00	$0
TAM Adj for Other Revs (205)								
1st 20,000 kWh, per kWh	186,966,147	186,253,147	186,649,079	kWh	0.023 ¢	$42,929	0.000 ¢	$0
All additional kWh, per kWh	1,078,620,232	1,074,388,005	1,077,030,703	kWh	0.020 ¢	$215,406	0.000 ¢	$0
Subtotal						$71,159,262		$75,191,500
Schedule 201								
1st 20,000 kWh, per kWh	186,966,147	186,253,147	186,649,079	kWh	2.831 ¢	$5,284,035	2.831 ¢	$5,284,035
All additional kWh, per kWh	1,078,620,232	1,074,388,005	1,077,030,703	kWh	2.454 ¢	$26,430,333	2.454 ¢	$26,430,333
Total	1,265,586,379	1,260,641,152	1,263,679,782	kWh		$102,873,630		$106,905,868
							Change	$4,032,238
Schedule No. 30/730 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	287,388	287,388	287,761	kW	$1.65	$474,806	$2.47	$710,770
System Usage Charge								
Sch 200 related, per kWh	97,554,175	97,554,175	97,745,891	kWh	0.065 ¢	$63,535	0.081 ¢	$79,174
T&A and Sch 201 related, per kWh	97,554,175	97,554,175	97,745,891	kWh	0.068 ¢	$66,467	0.073 ¢	$71,355
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	10	10	10	bill	$453.00	$4,530	$538.00	$5,380.00
Load Size 201-300 kW, per month	70	70	72	bill	$143.00	$10,296	$168.00	$12,096.00
Load Size > 300 kW, per month	578	578	592	bill	$371.00	$219,632	$437.00	$258,704.00
Load Size Charge								
≤ 200 Kw, per kW					No Charge		No Charge	
201-300 kW, per kW	18,704	18,704	18,767	kW	$1.55	$29,089	$1.85	$34,719
>300 kW, per kW	333,388	333,388	333,850	kW	$0.75	$250,388	$0.90	$300,465
Demand Charge, per kW	287,388	287,388	287,761	kW	$3.94	$1,133,778	$4.64	$1,335,211
Reactive Power Charge, per kvar	36,576	36,576	36,423	kvar	60.00 ¢	$21,854	60.00 ¢	$21,854
Energy Charge - Schedule 200								
Demand Charge, per kW	287,388	287,388	287,761	kW	$1.88	$540,127	$1.98	$569,767
1st 20,000 kWh, per kWh	12,873,800	12,873,800	12,894,541	kWh	2.789 ¢	$359,629	2.591 ¢	$334,098
All additional kWh, per kWh	84,680,375	84,680,375	84,851,350	kWh	2.411 ¢	$2,045,766	2.591 ¢	$2,198,498
Subtotal	97,554,175	97,554,175	97,745,891	kWh		$5,219,897		$5,932,091
Renewable Adjustment Clause (202), per kWh	97,554,175	97,554,175	97,745,891	kWh	0.149 ¢	$145,641	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	97,554,175	97,554,175	97,745,891	kWh	-0.021 ¢	($20,527)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	97,554,175	97,554,175	97,745,891	kWh	0.054 ¢	$52,783	0.000 ¢	$0
, per kW	287,388	287,388	287,761	kW	$0.37	$106,472	$0.00	$0
TAM Adj for Other Revs (205)								
1st 20,000 kWh, per kWh	12,873,800	12,873,800	12,894,541	kWh	0.022 ¢	$2,837	0.000 ¢	$0
All additional kWh, per kWh	84,680,375	84,680,375	84,851,350	kWh	0.020 ¢	$16,970	0.000 ¢	$0
Subtotal						$5,524,073		$5,932,091
Schedule 201								
1st 20,000 kWh, per kWh	12,873,800	12,873,800	12,894,541	kWh	2.800 ¢	$361,047	2.800 ¢	$361,047
All additional kWh, per kWh	84,680,375	84,680,375	84,851,350	kWh	2.420 ¢	$2,053,403	2.420 ¢	$2,053,403
Total	97,554,175	97,554,175	97,745,891	kWh		$7,938,523		$8,346,541
							Change	$408,018

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2019
Forecast 12 Months Ended December 31, 2021

Schedule	Actual 7/18-6/19 Units	Normalized 7/18-6/19 Units	Forecast 1/21 - 12/21 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 41/741 - Irrigation								
Agricultural Pumping Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	200,197,638	194,966,386	221,514,932	kWh	0.366 ¢	$810,745	0.645 ¢	$1,428,771
System Usage Charge								
Sch 200 related, per kWh	200,197,638	194,966,386	221,514,932	kWh	0.074 ¢	$163,921	0.074 ¢	$163,921
T&A and Sch 201 related, per kWh	200,197,638	194,966,386	221,514,932	kWh	0.076 ¢	$168,351	0.096 ¢	$212,654
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	5,623	5,623	6,698	bill	No Charge	$0	No Charge	$0
Three Phase Load Size 51 - 300 kW, per customer	981	981	1,169	bill	$310.00	$362,390	$390.00	$455,910
Three Phase Load Size > 300 kW, per customer	21	21	25	bill	$1,210.00	$30,250	$1,530.00	$38,250
Total Customers	6,625	6,625	7,892	bill				
Monthly Bills	48,363	48,363	57,612					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase ≤ 50 kW	99,767	99,767	113,352	kW	$15.00	$1,700,280	$19.00	$2,153,688
Three Phase Load Size 51-300 kW, per kW	86,279	86,279	98,028	kW	$10.00	$980,280	$13.00	$1,274,364
Three Phase Load Size > 300 kW, per kW	9,078	9,078	10,314	kW	$6.00	$61,884	$8.00	$82,512
Single Phase, Minimum Charge	424	424	505	bill	$55.00	$27,775	$70.00	$35,350
Three Phase, Minimum Charge	1,244	1,244	1,482	bill	$90.00	$133,380	$115.00	$170,430
Distribution Energy Charge, per kWh	200,197,638	194,966,386	221,514,932	kWh	3.569 ¢	$7,905,868	4.464 ¢	$9,888,427
Reactive Power Charge, per kvar	168,930	168,930	191,933	kvar	65.00 ¢	$124,756	65.00 ¢	$124,756
Energy Charge - Schedule 200								
Winter, 1st 100 kWh/kW, per kWh	2,230,984	2,230,984	2,534,777	kWh	4.629 ¢	$117,335	3.074 ¢	$77,919
Winter, All additional kWh, per kWh	1,652,950	1,652,950	1,878,032	kWh	3.156 ¢	$59,271	3.074 ¢	$57,731
Summer, All kWh, per kWh	196,313,704	191,082,452	217,102,123	kWh	3.156 ¢	$6,851,743	3.074 ¢	$6,673,719
Prime Summ. On Peak, per On-peak kWh	*120,884*	*120,884*	*137,345*	kWh	22.313 ¢	$30,646		
Prime Summ. Off Peak, per Off-peak kWh	*2,783,567*	*2,783,567*	*3,162,605*	kWh	-3.161 ¢	($99,970)		
Subtotal	200,197,638	194,966,386	221,514,932	kWh		$19,498,229		$22,838,402
Renewable Adjustment Clause (202), per kWh	200,197,638	194,966,386	221,514,932	kWh	0.154 ¢	$341,133	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	200,197,638	194,966,386	221,514,932	kWh	-0.021 ¢	($46,518)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	200,197,638	194,966,386	221,514,932	kWh	0.166 ¢	$367,715	0.000 ¢	$0
TAM Adj for Other Revs (205)								
Winter, 1st 100 kWh/kW, per kWh	2,230,984	2,230,984	2,534,777	kWh	0.030 ¢	$760	0.000 ¢	$0
Winter, All additional kWh, per kWh	1,652,950	1,652,950	1,878,032	kWh	0.021 ¢	$394	0.000 ¢	$0
Summer, All kWh, per kWh	196,313,704	191,082,452	217,102,123	kWh	0.021 ¢	$45,591	0.000 ¢	$0
Subtotal						$20,207,304		$22,838,402
Schedule 201								
Winter, 1st 100 kWh/kW, per kWh	2,230,984	2,230,984	2,534,777	kWh	3.781 ¢	$95,840	3.781 ¢	$95,840
Winter, All additional kWh, per kWh	1,652,950	1,652,950	1,878,032	kWh	2.575 ¢	$48,359	2.575 ¢	$48,359
Summer, All kWh, per kWh	196,313,704	191,082,452	217,102,123	kWh	2.575 ¢	$5,590,380	2.575 ¢	$5,590,380
Total	200,197,638	194,966,386	221,514,932	kWh		$25,941,883		$28,572,981
							Change	$2,631,098

Schedule	Actual 7/18-6/19 Units	Normalized 7/18-6/19 Units	Forecast 1/21 - 12/21 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 41/741 - Irrigation								
Agricultural Pumping Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	34,721	34,721	39,449	kWh	0.356 ¢	$140	0.627 ¢	$247
System Usage Charge								
Sch 200 related, per kWh	34,721	34,721	39,449	kWh	0.072 ¢	$28	0.072 ¢	$28
T&A and Sch 201 related, per kWh	34,721	34,721	39,449	kWh	0.074 ¢	$29	0.093 ¢	$37
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	1	1	1	bill	No Charge	$0	No Charge	$0
Three Phase Load Size 51 - 300 kW, per customer	1	1	1	bill	$300.00	$300	$380.00	$380
Three Phase Load Size > 300 kW, per customer	0	0	0	bill	$1,180.00	$0	$1,490.00	$0
Total Customers	2	2	2	bill				
Monthly Bills	20	20	20					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase ≤ 50 kW	10	10	11	kW	$15.00	$165	$18.00	$198
Three Phase Load Size 51-300 kW, per kW	73	73	83	kW	$10.00	$830	$13.00	$1,079
Three Phase Load Size > 300 kW, per kW	0	0	0	kW	$6.00	$0	$8.00	$0
Single Phase, Minimum Charge	0	0	0	bill	$55.00	$0	$70.00	$0
Three Phase, Minimum Charge	0	0	0	bill	$85.00	$0	$110.00	$0
Distribution Energy Charge, per kWh	34,721	34,721	39,449	kWh	3.468 ¢	$1,368	4.338 ¢	$1,711
Reactive Power Charge, per kvar	50	50	57	kvar	60.00 ¢	$34	60.00 ¢	$34
Energy Charge - Schedule 200								
Winter, 1st 100 kWh/kW, per kWh	481	481	546	kWh	4.497 ¢	$25	2.987 ¢	$16
Winter, All additional kWh, per kWh	0	0	0	kWh	3.066 ¢	$0	2.987 ¢	$0
Summer, All kWh, per kWh	34,240	34,240	38,903	kWh	3.066 ¢	$1,193	2.987 ¢	$1,162
Prime Summ. On Peak, per On-peak kWh	0	0	0	kWh	22.313 ¢	$0		
Prime Summ. Off Peak, per Off-peak kWh	0	0	0	kWh	-3.161 ¢	$0		
Subtotal	34,721	34,721	39,449	kWh		$4,112		$4,892
Renewable Adjustment Clause (202), per kWh	34,721	34,721	39,449	kWh	0.154 ¢	$61	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	34,721	34,721	39,449	kWh	-0.021 ¢	($8)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	34,721	34,721	39,449	kWh	0.161 ¢	$64	0.000 ¢	$0
TAM Adj for Other Revs (205)								
Winter, 1st 100 kWh/kW, per kWh	481	481	546	kWh	0.029 ¢	$0	0.000 ¢	$0
Winter, All additional kWh, per kWh	0	0	0	kWh	0.020 ¢	$0	0.000 ¢	$0
Summer, All kWh, per kWh	34,240	34,240	38,903	kWh	0.020 ¢	$8	0.000 ¢	$0
Subtotal						$4,237		$4,892
Schedule 201								
Winter, 1st 100 kWh/kW, per kWh	481	481	546	kWh	3.653 ¢	$20	3.653 ¢	$20
Winter, All additional kWh, per kWh	0	0	0	kWh	2.495 ¢	$0	2.495 ¢	$0
Summer, All kWh, per kWh	34,240	34,240	38,903	kWh	2.495 ¢	$971	2.495 ¢	$971
Total	34,721	34,721	39,449	kWh		$5,228		$5,883
							Change	$655

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2019
Forecast 12 Months Ended December 31, 2021

Schedule	Actual 7/18-6/19 Units	Normalized 7/18-6/19 Units	Forecast 1/21 - 12/21 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	109,490	109,490	113,283	kW	$1.40	$158,596		
credit per kW of on-peak demand (OATT)	0	0	0	kW	($1.40)	$0		
REV per kW of on-peak demand	108,456	108,456	112,213	kW			$2.39	$268,189
REV credit per kW of on-peak demand (OATT)	0	0	0	kW			($2.39)	$0
System Usage Charge								
Sch 200 related, per kWh	24,510,623	24,510,623	25,359,694	kWh	0.061 ¢	$15,469	0.075 ¢	$19,020
T&A and Sch 201 related, per kWh	24,510,623	24,510,623	25,359,694	kWh	0.082 ¢	$20,795	0.066 ¢	$16,737
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$460.00	$0	$610.00	$0
Facility Capacity > 4,000 kW, per month	12	12	12	bill	$830.00	$9,960	$1,100.00	$13,200
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$1.25	$0	$1.20	$0
Facility Capacity > 4,000 kW, per kW	130,454	130,454	134,973	kW	$1.15	$155,219	$1.10	$148,470
Demand Charge, per kW of on-peak demand	109,490	109,490	113,283	kW	$3.17	$359,107		
REV Demand Charge, per kW of on-peak demand	108,456	108,456	112,213	kW			$4.83	$541,989
Reactive Power Charge, per kvar	4,679	4,679	4,841	kvar	60.00 ¢	$2,905	60.00 ¢	$2,905
Reactive Hours, per kvarh	11,100,000	11,100,000	11,484,514	kvarh	0.080 ¢	$9,188	0.080 ¢	$9,188
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	130,454	130,454	134,973	kW	$0.27	$36,443	$0.27	$36,443
Supplemental Reserves, per kW of Facility Cap.	130,454	130,454	134,973	kW	$0.27	$36,443	$0.27	$36,443
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW Facil. Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	109,490	109,490	113,283	kW	$1.87	$211,386		
On-Peak, per on-peak kWh	17,359,438	17,359,438	17,960,785	kWh	2.443 ¢	$438,782		
Off-Peak, per off-peak kWh	7,151,185	7,151,185	7,398,909	kWh	2.393 ¢	$177,056		
REV Demand Charge, per kW of On-Peak demand	108,456	108,456	112,213	kW			$1.99	$223,304
REV On-Peak, per on-peak kWh	8,818,419	8,818,419	9,123,898	kWh			2.563 ¢	$233,846
REV Off-Peak, per off-peak kWh	15,692,204	15,692,204	16,235,796	kWh			2.563 ¢	$416,123
Unscheduled Energy, per kWh	1,060,924	1,060,924	1,097,675	kWh		$48,855		$48,855
Subtotal	25,571,547	25,571,547	26,457,369	kWh		$1,680,204		$2,014,712
Renewable Adjustment Clause (202), per kWh	25,571,547	25,571,547	26,457,369	kWh	0.140 ¢	$37,040	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	25,571,547	25,571,547	26,457,369	kWh	-0.019 ¢	($5,027)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	25,571,547	25,571,547	26,457,369	kWh	0.053 ¢	$14,022	0.000 ¢	$0
, per kW	109,490	109,490	113,283	kW	$0.45	$50,977	$0.00	$0
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	17,359,438	17,359,438	17,960,785	kWh	0.018 ¢	$3,233	0.000 ¢	$0
Off-Peak, per off-peak kWh	7,151,185	7,151,185	7,398,909	kWh	0.018 ¢	$1,332	0.000 ¢	$0
Subtotal						$1,781,781		$2,014,712
Schedule 201								
On-Peak, per on-peak kWh	17,359,438	17,359,438	17,960,785	kWh	2.317 ¢	$416,151	2.317 ¢	$416,151
Off-Peak, per off-peak kWh	7,151,185	7,151,185	7,398,909	kWh	2.267 ¢	$167,733	2.267 ¢	$167,733
Total	25,571,547	25,571,547	26,457,369	kWh		$2,365,665		$2,598,596
							Change	$232,931
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	169,385	169,385	169,697	kW	$1.76	$298,667		
credit per kW of on-peak demand (OATT)	0	0	0	kW	($1.76)	$0		
REV per kW of on-peak demand	167,786	167,786	168,095	kW			$3.19	$536,223
REV credit per kW of on-peak demand (OATT)	0	0	0	kW			($3.19)	$0
System Usage Charge								
Sch 200 related, per kWh	14,291,309	14,291,309	14,628,150	kWh	0.057 ¢	$8,338	0.073 ¢	$10,679
T&A and Sch 201 related, per kWh	14,291,309	14,291,309	14,628,150	kWh	0.061 ¢	$8,923	0.063 ¢	$9,216
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	24	24	24	bill	$860.00	$20,640	$820.00	$19,680
Facility Capacity > 4,000 kW, per month	35	35	35	bill	$1,600.00	$56,000	$1,520.00	$53,200
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	35,825	35,825	37,066	kW	$1.35	$50,039	$1.25	$46,333
Facility Capacity > 4,000 kW, per kW	310,558	310,558	308,855	kW	$1.35	$416,954	$1.25	$386,069
Demand Charge, per kW of on-peak demand	169,385	169,385	169,697	kW	$3.61	$612,606		
REV Demand Charge, per kW of on-peak demand	167,786	167,786	168,095	kW			$3.48	$584,971
Reactive Power Charge, per kvar	136,960	136,960	137,289	kvar	55.00 ¢	$75,509	55.00 ¢	$75,509
Reactive Hours, per kvarh	28,772,372	28,772,372	28,348,947	kvarh	0.080 ¢	$22,679	0.080 ¢	$22,679
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	346,383	346,383	345,921	kW	$0.27	$93,399	$0.27	$93,399
Supplemental Reserves, per kW of Facility Cap.	346,383	346,383	345,921	kW	$0.27	$93,399	$0.27	$93,399
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW Facil. Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	169,385	169,385	169,697	kW	$1.88	$318,521		
On-Peak, per on-peak kWh	8,129,269	8,129,269	8,310,064	kWh	2.353 ¢	$195,536		
Off-Peak, per off-peak kWh	6,162,040	6,162,040	6,318,086	kWh	2.303 ¢	$145,506		
REV Demand Charge, per kW of On-Peak demand	167,786	167,786	168,095				$2.03	$341,233
REV On-Peak, per on-peak kWh	5,141,720	5,141,720	5,262,908				2.511 ¢	$132,152
REV Off-Peak, per off-peak kWh	9,149,589	9,149,589	9,365,241				2.511 ¢	$235,161
Unscheduled Energy, per kWh	811,187	811,187	812,836	kWh		$17,397		$17,397
Subtotal	15,102,496	15,102,496	15,440,986	kWh		$2,434,113		$2,657,300
Renewable Adjustment Clause (202), per kWh	15,102,496	15,102,496	15,440,986	kWh	0.140 ¢	$21,617	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	15,102,496	15,102,496	15,440,986	kWh	-0.019 ¢	($2,934)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	15,102,496	15,102,496	15,440,986	kWh	0.048 ¢	$7,412	0.000 ¢	$0
, per kW	169,385	169,385	169,697	kW	$0.62	$105,212	$0.00	$0
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	8,129,269	8,129,269	8,310,064	kWh	0.017 ¢	$1,413	0.000 ¢	$0
Off-Peak, per off-peak kWh	6,162,040	6,162,040	6,318,086	kWh	0.017 ¢	$1,074	0.000 ¢	$0
Subtotal						$2,567,907		$2,657,300
Schedule 201								
On-Peak, per on-peak kWh	8,129,269	8,129,269	8,310,064	kWh	2.176 ¢	$180,827	2.176 ¢	$180,827
Off-Peak, per off-peak kWh	6,162,040	6,162,040	6,318,086	kWh	2.126 ¢	$134,323	2.126 ¢	$134,323
Total	15,102,496	15,102,496	15,440,986	kWh		$2,883,057		$2,972,450
							Change	$89,393

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2019
Forecast 12 Months Ended December 31, 2021

Schedule	Actual 7/18-6/19 Units	Normalized 7/18-6/19 Units	Forecast 1/21 - 12/21 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 76R/776R								
Large General Service/Partial Requirements Service - Economic Replacement Power Rider								
Transmission & Ancillary Services Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.049	$0	$0.086	$0
Primary	0	0	0	kW	$0.055	$0	$0.093	$0
Transmission	0	0	0	kW	$0.068	$0	$0.124	$0
Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.146	$0	$0.182	$0
Primary	0	0	0	kW	$0.124	$0	$0.188	$0
Transmission	0	0	0	kW	$0.141	$0	$0.136	$0
Schedule No. 48/748 - Composite								
Large General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	1,449,003	1,449,003	1,414,375	kW	$1.80	$2,545,875		
REV per kW of on-peak demand	1,435,324	1,435,324	1,401,024	kW			$2.76	$3,866,826
System Usage Charge								
Sch 200 related, per kWh	576,157,983	568,751,215	555,158,233	kWh	0.067 ¢	$371,956	0.076 ¢	$421,920
T&A and Sch 201 related, per kWh	576,157,983	568,751,215	555,158,233	kWh	0.069 ¢	$383,059	0.068 ¢	$377,508
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	1,166	1,166	1,173	bill	$420.00	$492,660	$640.00	$750,720
Facility Capacity > 4,000 kW, per month	13	13	13	bill	$800.00	$10,400	$1,220.00	$15,860
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,587,904	1,587,904	1,547,051	kW	$1.15	$1,779,109	$2.70	$4,177,038
Facility Capacity > 4,000 kW, per kW	154,894	154,894	156,285	kW	$1.10	$171,914	$2.60	$406,341
Demand Charge, per kW of on-peak demand	1,449,003	1,449,003	1,414,375	kW	$3.74	$5,289,763		
REV Demand Charge, per kW of on-peak demand	1,435,324	1,435,324	1,401,024	kW			$4.68	$6,556,792
Reactive Power Charge, per kvar	381,774	381,774	372,291	kvar	65.00 ¢	$241,989	65.00 ¢	$241,989
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,449,003	1,449,003	1,414,375	kW	$1.83	$2,593,964		
On-Peak, per on-peak kWh	361,983,162	357,492,162	348,874,397	kWh	2.581 ¢	$9,004,448		
Off-Peak, per off-peak kWh	214,174,821	211,259,053	206,283,836	kWh	2.531 ¢	$5,221,044		
REV Demand Charge, per kW of On-Peak demand	1,435,324	1,435,324	1,401,024				$1.94	$2,717,987
REV On-Peak, per on-peak kWh	207,289,823	204,625,823	199,735,357				2.685 ¢	$5,362,894
REV Off-Peak, per off-peak kWh	368,868,160	364,125,392	355,422,876				2.685 ¢	$9,543,104
Subtotal	576,157,983	568,751,215	555,158,233	kWh		$28,106,181		$34,438,979
Renewable Adjustment Clause (202), per kWh	576,157,983	568,751,215	555,158,233	kWh	0.140 ¢	$777,222	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	576,157,983	568,751,215	555,158,233	kWh	-0.019 ¢	($105,480)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	576,157,983	568,751,215	555,158,233	kWh	0.054 ¢	$299,785	0.000 ¢	$0
, per kW	1,449,003	1,449,003	1,414,375	kW	$0.41	$579,894	$0.00	$0
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	361,983,162	357,492,162	348,874,397	kWh	0.020 ¢	$69,775	0.000 ¢	$0
Off-Peak, per off-peak kWh	214,174,821	211,259,053	206,283,836	kWh	0.020 ¢	$41,257	0.000 ¢	$0
Subtotal						$29,768,634		$34,438,979
Schedule 201								
On-Peak, per on-peak kWh	361,983,162	357,492,162	348,874,397	kWh	2.497 ¢	$8,711,394	2.497 ¢	$8,711,394
Off-Peak, per off-peak kWh	214,174,821	211,259,053	206,283,836	kWh	2.447 ¢	$5,047,765	2.447 ¢	$5,047,765
Total	576,157,983	568,751,215	555,158,233	kWh		$43,527,793		$48,198,138
							Change	$4,670,345
Schedule No. 48/748 - Composite								
Large General Service (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	3,434,988	3,434,988	3,350,490	kW	$1.94	$6,499,951		
REV per kW of on-peak demand	3,402,562	3,402,562	3,318,861	kW			$2.93	$9,724,263
System Usage Charge								
Sch 200 related, per kWh	1,582,417,807	1,582,417,807	1,543,656,476	kWh	0.061 ¢	$941,630	0.075 ¢	$1,157,742
T&A and Sch 201 related, per kWh	1,582,417,807	1,582,417,807	1,543,656,476	kWh	0.082 ¢	$1,265,798	0.066 ¢	$1,018,813
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	721	721	725	bill	$460.00	$333,500	$610.00	$442,250
Facility Capacity > 4,000 kW, per month	348	348	349	bill	$830.00	$289,670	$1,100.00	$383,900
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,511,241	1,511,241	1,472,971	kW	$1.25	$1,841,214	$1.20	$1,767,565
Facility Capacity > 4,000 kW, per kW	2,642,267	2,642,267	2,583,820	kW	$1.15	$2,971,393	$1.10	$2,842,202
Demand Charge, per kW of on-peak demand	3,434,988	3,434,988	3,350,490	kW	$3.17	$10,621,053		
REV Demand Charge, per kW of on-peak demand	3,402,562	3,402,562	3,318,861	kW			$4.83	$16,030,099
Reactive Power Charge, per kvar	802,196	802,196	781,599	kvar	60.00 ¢	$468,959	60.00 ¢	$468,959
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	3,434,988	3,434,988	3,350,490	kW	$1.87	$6,252,014		
On-Peak, per on-peak kWh	950,603,128	950,603,128	927,232,528	kWh	2.443 ¢	$22,652,291		
Off-Peak, per off-peak kWh	631,814,679	631,814,679	616,423,948	kWh	2.393 ¢	$14,751,025		
REV Demand Charge, per kW of On-Peak demand	3,402,562	3,402,562	3,318,861	kW			$1.99	$6,604,533
REV On-Peak, per on-peak kWh	569,321,465	569,321,465	555,375,933	kWh			2.563 ¢	$14,234,285
REV Off-Peak, per off-peak kWh	1,013,096,342	1,013,096,342	988,280,543	kWh			2.563 ¢	$25,329,630
Subtotal	1,582,417,807	1,582,417,807	1,543,656,476	kWh		$68,888,498		$80,004,241
Renewable Adjustment Clause (202), per kWh	1,582,417,807	1,582,417,807	1,543,656,476	kWh	0.140 ¢	$2,161,119	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	1,582,417,807	1,582,417,807	1,543,656,476	kWh	-0.019 ¢	($293,295)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	1,582,417,807	1,582,417,807	1,543,656,476	kWh	0.053 ¢	$818,138	0.000 ¢	$0
, per kW	3,434,988	3,434,988	3,350,490	kW	$0.45	$1,507,721	$0.00	$0
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	950,603,128	950,603,128	927,232,528	kWh	0.018 ¢	$166,902	0.000 ¢	$0
Off-Peak, per off-peak kWh	631,814,679	631,814,679	616,423,948	kWh	0.018 ¢	$110,956	0.000 ¢	$0
Subtotal						$73,360,039		$80,004,241
Schedule 201								
On-Peak, per on-peak kWh	950,603,128	950,603,128	927,232,528	kWh	2.317 ¢	$21,483,978	2.317 ¢	$21,483,978
Off-Peak, per off-peak kWh	631,814,679	631,814,679	616,423,948	kWh	2.267 ¢	$13,974,331	2.267 ¢	$13,974,331
Total	1,582,417,807	1,582,417,807	1,543,656,476	kWh		$108,818,348		$115,462,550
							Change	$6,644,202

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2019
Forecast 12 Months Ended December 31, 2021

Schedule	Actual 7/18-6/19 Units	Normalized 7/18-6/19 Units	Forecast 1/21 - 12/21 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 48/748 - Composite								
Large General Service (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	874,788	874,788	1,467,250	kW	$2.30	$3,374,675		
REV per kW of on-peak demand	871,051	871,051	1,461,474	kW			$3.73	$5,451,298
System Usage Charge								
Sch 200 related, per kWh	575,018,000	575,018,000	981,022,703	kWh	0.057 ¢	$559,183	0.073 ¢	$716,147
T&A and Sch 201 related, per kWh	575,018,000	575,018,000	981,022,703	kWh	0.061 ¢	$598,424	0.063 ¢	$618,044
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	53	53	53	bill	$860.00	$45,580	$820.00	$43,460
Facility Capacity > 4,000 kW, per month	26	26	26	bill	$1,600.00	$41,600	$1,520.00	$39,520
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	51,945	51,945	50,600	kW	$1.35	$68,310	$1.25	$63,250
Facility Capacity > 4,000 kW, per kW	853,649	853,649	1,454,678	kW	$1.35	$1,963,815	$1.25	$1,818,348
Demand Charge, per kW of on-peak demand	874,788	874,788	1,467,250	kW	$3.61	$5,296,773		
REV Demand Charge, per kW of on-peak demand	871,051	871,051	1,461,474	kW			$3.48	$5,085,930
Reactive Power Charge, per kvar	31,001	31,001	30,194	kvar	55.00 ¢	$16,607	55.00 ¢	$16,607
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	874,788	874,788	1,467,250	kW	$1.88	$2,754,028		
On-Peak, per on-peak kWh	325,135,000	325,135,000	554,713,687	kWh	2.353 ¢	$13,052,413		
Off-Peak, per off-peak kWh	249,883,000	249,883,000	426,309,016	kWh	2.303 ¢	$9,817,897		
REV Demand Charge, per kW of On-Peak demand	871,051	871,051	1,461,474				$2.03	$2,966,792
REV On-Peak, per on-peak kWh	192,107,014	192,107,014	326,571,426				2.511 ¢	$8,200,209
REV Off-Peak, per off-peak kWh	382,910,986	382,910,986	654,451,277				2.511 ¢	$16,433,272
Subtotal	575,018,000	575,018,000	981,022,703	kWh		$37,589,305		$41,452,877
Renewable Adjustment Clause (202), per kWh	575,018,000	575,018,000	981,022,703	kWh	0.140 ¢	$1,373,432	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	575,018,000	575,018,000	981,022,703	kWh	-0.019 ¢	($186,394)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	575,018,000	575,018,000	981,022,703	kWh	0.048 ¢	$470,891	0.000 ¢	$0
, per kW	874,788	874,788	1,467,250	kW	$0.62	$909,695	$0.00	$0
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	325,135,000	325,135,000	554,713,687	kWh	0.017 ¢	$94,301	0.000 ¢	$0
Off-Peak, per off-peak kWh	249,883,000	249,883,000	426,309,016	kWh	0.017 ¢	$72,473	0.000 ¢	$0
Subtotal						$40,323,703		$41,452,877
Schedule 201								
On-Peak, per on-peak kWh	325,135,000	325,135,000	554,713,687	kWh	2.176 ¢	$12,070,570	2.176 ¢	$12,070,570
Off-Peak, per off-peak kWh	249,883,000	249,883,000	426,309,016	kWh	2.126 ¢	$9,063,330	2.126 ¢	$9,063,330
Total	575,018,000	575,018,000	981,022,703	kWh		$61,457,603		$62,586,777
							Change	$1,129,174
Schedule No. 848 - Commercial								
Distribution Only Large General Service (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	387,115	387,115	0	kW	$2.30	$0		
REV per kW of on-peak demand	383,461	383,461	0	kW			$3.73	$0
System Usage Charge								
Sch 200 related, per kWh	252,108,000	252,108,000	0	kWh	0.057 ¢	$0	0.073 ¢	$0
T&A and Sch 201 related, per kWh	252,108,000	252,108,000	0	kWh	0.061 ¢	$0	0.063 ¢	$0
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$860.00	$0	$820.00	$0
Facility Capacity > 4,000 kW, per month	12	12	12	bill	$1,600.00	$19,200	$1,520.00	$18,240
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$1.35	$0	$1.25	$0
Facility Capacity > 4,000 kW, per kW	450,358	450,358	494,703	kW	$1.35	$667,849	$1.25	$618,379
Demand Charge, per kW of on-peak demand	387,115	387,115	425,233	kW	$3.61	$1,535,091		
REV Demand Charge, per kW of on-peak demand	383,461	383,461	425,233	kW			$3.48	$1,479,811
Reactive Power Charge, per kvar	0	0	0	kvar	55.00 ¢	$0	55.00 ¢	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	387,115	387,115	0	kW	$1.88	$0		
On-Peak, per on-peak kWh	141,807,000	141,807,000	0	kWh	2.353 ¢	$0		
Off-Peak, per off-peak kWh	110,301,000	110,301,000	0	kWh	2.303 ¢	$0		
REV Demand Charge, per kW of On-Peak demand	252,108,000	252,108,000	0	kW			$2.03	$0
REV On-Peak, per on-peak kWh	90,703,287	90,703,287	0	kWh			2.511 ¢	$0
REV Off-Peak, per off-peak kWh	161,404,713	161,404,713	0	kWh			2.511 ¢	$0
Subtotal	252,108,000	252,108,000	0	kWh		$2,222,140		$2,116,430
Renewable Adjustment Clause (202), per kWh	252,108,000	252,108,000	0	kWh	0.140 ¢	$0	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	252,108,000	252,108,000	0	kWh	-0.019 ¢	$0	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	252,108,000	252,108,000	0	kWh	0.048 ¢	$0	0.000 ¢	$0
, per kW	387,115	387,115	0	kW	$0.62	$0	$0.00	$0
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	141,807,000	141,807,000	0	kWh	0.017 ¢	$0	0.000 ¢	$0
Off-Peak, per off-peak kWh	110,301,000	110,301,000	0	kWh	0.017 ¢	$0	0.000 ¢	$0
Subtotal						$2,222,140		$2,116,430
Schedule 201								
On-Peak, per on-peak kWh	141,807,000	141,807,000	0	kWh	2.176 ¢	$0	2.176 ¢	$0
Off-Peak, per off-peak kWh	110,301,000	110,301,000	0	kWh	2.126 ¢	$0	2.126 ¢	$0
Total	252,108,000	252,108,000		kWh		$2,222,140		$2,116,430
Energy Delivered	252,108,000	252,108,000	279,378,179				Change	($105,710)

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2019
Forecast 12 Months Ended December 31, 2021

Schedule	Actual 7/18-6/19 Units	Normalized 7/18-6/19 Units	Forecast 1/21 - 12/21 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 15 - Composite								
Outdoor Area Lighting Service								
No. of Customers	6,326	6,326	6,045					
Transmission & Ancillary Services Charge								
per kWh	9,043,776	9,043,776	8,693,135	kWh	0.075 ¢	$6,643	0.065 ¢	$5,615
System Usage Charge								
Sch 200 related, per kWh	9,043,776	9,043,776	8,693,135	kWh	0.046 ¢	$3,669	0.033 ¢	$2,897
T&A and Sch 201 related, per kWh	9,043,776	9,043,776	8,693,135	kWh	0.048 ¢	$4,269	0.024 ¢	$2,117
Distribution Charge								
Distribution Charge, per kWh	9,043,776	9,043,776	8,693,135	kWh	8.468 ¢	$735,615	9.671 ¢	$840,705
Energy Charge - Schedule 200								
per kWh	9,043,776	9,043,776	8,693,135	kWh	2.270 ¢	$197,497	1.133 ¢	$98,485
Subtotal	9,043,776	9,043,776	8,693,135	kWh		$947,694		$949,818
Renewable Adjustment Clause (202), per kWh	9,043,776	9,043,776	8,693,135	kWh	0.124 ¢	$10,779	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	9,043,776	9,043,776	8,693,135	kWh	-0.015 ¢	($1,304)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	9,043,776	9,043,776	8,693,135	kWh	0.120 ¢	$10,432	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	9,043,776	9,043,776	8,693,135	kWh	0.017 ¢	$1,478	0.000 ¢	$0
Subtotal						$969,079		$949,818
Schedule 201								
per kWh	9,043,776	9,043,776	8,693,135	kWh	2.037 ¢	$177,106	2.037 ¢	$177,106
Total	9,043,776	9,043,776	8,693,135	kWh		$1,146,185		$1,126,924
							Change	($19,261)
Schedule No. 50								
Mercury Vapor Street Lighting Service								
No. of Customers	226	226	229					
Transmission & Ancillary Services Charge								
per kWh	7,272,772	7,272,772	6,031,743	kWh	0.075 ¢	$4,720		
System Usage Charge								
Sch 200 related, per kWh	7,272,772	7,272,772	6,031,743	kWh	0.046 ¢	$2,468		
T&A and Sch 201 related, per kWh	7,272,772	7,272,772	6,031,743	kWh	0.048 ¢	$3,099		
Distribution Charge								
Distribution Charge, per kWh	7,272,772	7,272,772	6,031,743	kWh	7.022 ¢	$423,585		
Energy Charge - Schedule 200								
per kWh	7,272,772	7,272,772	6,031,743	kWh	2.047 ¢	$123,737		
Subtotal	7,272,772	7,272,772	6,031,743	kWh		$557,609		
Renewable Adjustment Clause (202), per kWh	7,272,772	7,272,772	6,031,743	kWh	0.108 ¢	$6,514		
Adj to Remove Deer Creek (196), per kWh	7,272,772	7,272,772	6,031,743	kWh	-0.015 ¢	($905)		
Schedule 80 Adjustment, per kWh	7,272,772	7,272,772	6,031,743	kWh	0.120 ¢	$7,238		
TAM Adj for Other Revs (205), per kWh	7,272,772	7,272,772	6,031,743	kWh	0.013 ¢	$784		
Subtotal						$571,240		
Schedule 201								
per kWh	7,272,772	7,272,772	6,031,743	kWh	1.681 ¢	$101,541		
Total	7,272,772	7,272,772	6,031,743	kWh		$672,781		
Schedule No. 51/751								
Street Lighting Service, Company-Owned System								
No. of Customers	831	831	833					
Transmission & Ancillary Services Charge								
per kWh	19,719,845	19,719,845	13,842,798	kWh	0.075 ¢	$9,720		
System Usage Charge								
Sch 200 related, per kWh	19,719,845	19,719,845	13,842,798	kWh	0.046 ¢	$6,176		
T&A and Sch 201 related, per kWh	19,719,845	19,719,845	13,842,798	kWh	0.048 ¢	$6,271		
Distribution Charge								
Distribution Charge, per kWh	19,719,845	19,719,845	13,842,798	kWh	11.735 ¢	$1,624,489		
Energy Charge - Schedule 200								
per kWh	19,719,845	19,719,845	13,842,798	kWh	3.233 ¢	$447,182		
Subtotal	19,719,845	19,719,845	13,842,798	kWh		$2,093,838		
Renewable Adjustment Clause (202), per kWh	19,719,845	19,719,845	13,842,798	kWh	0.152 ¢	$21,041		
Adj to Remove Deer Creek (196), per kWh	19,719,845	19,719,845	13,842,798	kWh	-0.015 ¢	($2,076)		
Schedule 80 Adjustment, per kWh	19,719,845	19,719,845	13,842,798	kWh	0.120 ¢	$16,611		
TAM Adj for Other Revs (205), per kWh	19,719,845	19,719,845	13,842,798	kWh	0.020 ¢	$2,769		
Subtotal						$2,132,183		
Schedule 201								
per kWh	19,719,845	19,719,845	13,842,798	kWh	2.649 ¢	$367,191		
Total	19,719,845	19,719,845	13,842,798	kWh		$2,499,374		
Schedule No. 51/751 - Proposed Combined								
Street Lighting Service, Company-Owned System								
No. of Customers			1,097					
Transmission & Ancillary Services Charge								
per kWh			20,238,069	kWh		$14,713	0.079 ¢	$15,899
System Usage Charge								
Sch 200 related, per kWh			20,238,069	kWh		$8,811	0.041 ¢	$8,202
T&A and Sch 201 related, per kWh			20,238,069	kWh		$9,545	0.030 ¢	$5,993
Distribution Charge								
Distribution Charge, per kWh			20,238,069	kWh		$2,078,118	11.762 ¢	$2,380,483
Energy Charge - Schedule 200								
per kWh			20,238,069	kWh		$579,924	1.378 ¢	$278,862
Subtotal			20,238,069	kWh		$2,691,110		$2,689,439
Renewable Adjustment Clause (202), per kWh			20,238,069	kWh		$28,002	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh			20,238,069	kWh		($3,036)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh			20,238,069	kWh		$24,285	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh			20,238,069	kWh		$3,615	0.000 ¢	$0
Subtotal						$2,743,976		$2,689,439
Schedule 201								
per kWh			20,238,069	kWh		$476,108	2.353 ¢	$476,108
Total			20,238,069	kWh		$3,220,084		$3,165,548
							Change	($54,537)

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2019
Forecast 12 Months Ended December 31, 2021

Schedule	Actual 7/18-6/19 Units	Normalized 7/18-6/19 Units	Forecast 1/21 - 12/21 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 52/752								
Street Lighting Service, Company-Owned System								
No. of Customers	35	35	35					
Transmission & Ancillary Services Charge								
per kWh	365,649	365,649	363,528	kWh	0.075 ¢	$273		
System Usage Charge								
Sch 200 related, per kWh	365,649	365,649	363,528	kWh	0.046 ¢	$167		
T&A and Sch 201 related, per kWh	365,649	365,649	363,528	kWh	0.048 ¢	$175		
Distribution Charge								
Distribution Charge, per kWh	365,649	365,649	363,528	kWh	8.263 ¢	$30,044		
Energy Charge - Schedule 200								
per kWh	365,649	365,649	363,528	kWh	2.477 ¢	$9,005		
Subtotal	365,649	365,649	363,528	kWh		$39,663		
Renewable Adjustment Clause (202), per kWh	365,649	365,649	363,528	kWh	0.123 ¢	$447		
Adj to Remove Deer Creek (196), per kWh	365,649	365,649	363,528	kWh	-0.015 ¢	($55)		
Schedule 80 Adjustment, per kWh	365,649	365,649	363,528	kWh	0.120 ¢	$436		
TAM Adj for Other Revs (205), per kWh	365,649	365,649	363,528	kWh	0.017 ¢	$62		
Subtotal						$40,553		
Schedule 201								
per kWh	365,649	365,649	363,528	kWh	2.029 ¢	$7,376		
Total	365,649	365,649	363,528	kWh		$47,929		
Schedule No. 53/753								
Street Lighting Service, Consumer-Owned System								
No. of Customers	302	302	302					
Transmission & Ancillary Services Charge								
per kWh	11,922,142	11,922,142	12,045,888	kWh	0.075 ¢	$9,034	0.031 ¢	$3,734
System Usage Charge								
Sch 200 related, per kWh	11,922,142	11,922,142	12,045,888	kWh	0.046 ¢	$5,541	0.016 ¢	$1,927
T&A and Sch 201 related, per kWh	11,922,142	11,922,142	12,045,888	kWh	0.048 ¢	$5,782	0.012 ¢	$1,446
Distribution Charge								
Distribution Charge, per kWh	11,922,142	11,922,142	12,045,888	kWh	3.991 ¢	$480,796	4.684 ¢	$564,274
Energy Charge - Schedule 200								
per kWh	11,922,142	11,922,142	12,045,888	kWh	1.057 ¢	$127,325	0.549 ¢	$66,132
Subtotal	11,922,142	11,922,142	12,045,888	kWh		$628,479		$637,513
Renewable Adjustment Clause (202), per kWh	11,922,142	11,922,142	12,045,888	kWh	0.070 ¢	$8,432	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	11,922,142	11,922,142	12,045,888	kWh	-0.015 ¢	($1,807)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	11,922,142	11,922,142	12,045,888	kWh	0.120 ¢	$14,455	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	11,922,142	11,922,142	12,045,888	kWh	0.007 ¢	$843	0.000 ¢	$0
Subtotal						$650,402		$637,513
Schedule 201								
per kWh	11,922,142	11,922,142	12,045,888	kWh	0.864 ¢	$104,076	0.864 ¢	$104,076
Total	11,922,142	11,922,142	12,045,888	kWh		$754,478		$741,590
							Change	($12,889)
Schedule No. 54/754								
Recreational Field Lighting								
Transmission & Ancillary Services Charge								
per kWh	1,486,431	1,486,431	1,457,127	kWh	0.075 ¢	$1,093	0.039 ¢	$568
System Usage Charge								
Sch 200 related, per kWh	1,486,431	1,486,431	1,457,127	kWh	0.046 ¢	$670	0.020 ¢	$291
T&A and Sch 201 related, per kWh	1,486,431	1,486,431	1,457,127	kWh	0.048 ¢	$699	0.015 ¢	$219
Distribution Charge								
Basic Charge, Single Phase, per month	816	816	815	bill	$6.00	$4,890	$6.00	$4,890
Basic Charge, Three Phase, per month	445	445	445	bill	$9.00	$4,005	$9.00	$4,005
Distribution Energy Charge, per kWh	1,486,431	1,486,431	1,457,127	kWh	3.984 ¢	$58,052	5.287 ¢	$77,038
Energy Charge - Schedule 200								
per kWh	1,486,431	1,486,431	1,457,127	kWh	1.820 ¢	$26,520	0.691 ¢	$10,069
Subtotal	1,486,431	1,486,431	1,457,127	kWh		$95,929		$97,080
Renewable Adjustment Clause (202), per kWh	1,486,431	1,486,431	1,457,127	kWh	0.099 ¢	$1,443	0.000 ¢	$0
Adj to Remove Deer Creek (196), per kWh	1,486,431	1,486,431	1,457,127	kWh	-0.015 ¢	($219)	0.000 ¢	$0
Schedule 80 Adjustment, per kWh	1,486,431	1,486,431	1,457,127	kWh	0.120 ¢	$1,749	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	1,486,431	1,486,431	1,457,127	kWh	0.010 ¢	$146	0.000 ¢	$0
Subtotal						$99,048		$97,080
Schedule 201								
per kWh	1,486,431	1,486,431	1,457,127	kWh	1.492 ¢	$21,740	1.492 ¢	$21,740
Total	1,486,431	1,486,431	1,457,127	kWh		$120,788		$118,820
							Change	($1,968)
Subtotal Oregon	13,409,346,477	13,381,636,287	13,437,149,878			$1,304,556,743		$1,382,575,243
Employee Discount						($392,159)		($417,495)
TOTAL OREGON	**13,409,346,477**	**13,381,636,287**	**13,437,149,878**			**$1,304,164,584**		**$1,382,157,748**
Distribution Only Energy			279,378,179					
Total Energy Including Distribution Only	13,409,346,477	13,381,636,287	13,716,528,058					

Docket No. UE 374
Exhibit PAC/1410
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Estimated Effect of Proposed Rates and Proposed Adjustment Schedules

February 2020

Table 1410-1

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, 2021

						Present Revenues ($000)			Proposed Revenues ($000)			Change				
												Base Rates		Net Rates		
Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)	
	Residential															
1	Residential	4	4	517,740	5,521,127	$628,518	$8,453	$636,972	$668,438	$282	$668,720	$39,920	6.4%	$31,749	5.0%	1
2	**Total Residential**			517,740	5,521,127	$628,518	$8,453	$636,972	$668,438	$282	$668,720	$39,920	6.4%	$31,749	5.0%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	82,822	1,130,147	$126,081	$5,748	$131,829	$139,627	($151)	$139,476	$13,547	10.7%	$7,647	5.8%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,562	2,038,726	$186,682	$4,020	$190,703	$191,591	$6,813	$198,404	$4,908	2.6%	$7,701	4.0%	4
5	Gen. Svc. 201 - 999 kW	30	30	880	1,361,426	$110,812	$1,603	$112,415	$115,252	$1,752	$117,005	$4,440	4.0%	$4,590	4.1%	5
6	Large General Service >= 1,000 kW	48	48	195	3,079,837	$213,804	($8,589)	$205,215	$226,247	($3,452)	$222,795	$12,444	5.8%	$17,581	8.6%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	6	41,898	$5,249	($114)	$5,135	$5,571	($41)	$5,530	$322	5.8%	$396	8.6%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	1	0	$2,222	$12	$2,234	$2,116	$12	$2,128	($106)	9.0%	($106)	8.7%	8
9	Agricultural Pumping Service	41	41	7,894	221,554	$25,947	($1,115)	$24,832	$28,579	($1,277)	$27,302	$2,632	10.1%	$2,470	10.0%	9
10	**Total Commercial & Industrial**			102,360	7,873,589	$670,797	$1,565	$672,362	$708,984	$3,657	$712,641	$38,187	5.7%	$40,279	6.0%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	6,045	8,693	$1,146	$214	$1,361	$1,127	($10)	$1,117	($19)	-1.7%	($244)	-17.9%	11
12	Street Lighting Service Comp. Owned	50,51,52	51	1,097	20,238	$3,220	$664	$3,884	$3,166	($31)	$3,134	($55)	-1.7%	($750)	-19.3%	12
13	Street Lighting Service Cust. Owned	53	53	302	12,046	$754	$154	$908	$742	($4)	$737	($13)	-1.7%	($171)	-18.9%	13
14	Recreational Field Lighting	54	54	105	1,457	$121	$24	$145	$119	($1)	$118	($2)	-1.6%	($27)	-18.5%	14
15	**Total Public Street Lighting**			7,549	42,434	$5,242	$1,056	$6,298	$5,153	($47)	$5,106	($89)	-1.7%	($1,191)	-18.9%	15
16	**Subtotal**			627,649	13,437,150	$1,304,557	$11,074	$1,315,631	$1,382,575	$3,892	$1,386,468	$78,018	6.0%	$70,836	5.4%	16
17	Emplolyee Discount			*1,036*	*13,933*	($392)	($5)	($397)	($417)	($0)	($417)	($25)		($20)		17
18	AGA Revenue					$2,993		$2,993	$2,993		$2,993	$0		$0		18
19	COOC Amortization					$1,727		$1,727	$1,727		$1,727	$0		$0		19
20	**Total Sales with AGA**			627,649	13,437,150	$1,308,885	$11,069	$1,319,954	$1,386,878	$3,892	$1,390,770	$77,993	6.0%	$70,816	5.4%	20

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Table 1410-2 GRC Price Change - with Estimated Renewable Adjustment Clau

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, 2021

Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Present Revenues ($000) Base Rates	Present Revenues ($000) Estimated RAC	Present Revenues ($000) Base + RAC	Present Revenues ($000) Adders[1]	Present Revenues ($000) Net Rates	Proposed Revenues ($000) Base Rates	Proposed Revenues ($000) Adders[1]	Proposed Revenues ($000) Net Rates	Change Base + RAC ($000)	Change Base + RAC %[2]	Change Net Rates ($000)	Change Net Rates %[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	
								(6) + (7)		(8) + (9)			(11) + (12)	(11) - (8)	(14)/(8)	(13) - (10)	(16)/(10)	
	Residential																	
1	Residential	4	4	517,740	5,521,127	$628,518	$4,086	$632,604	$8,453	$641,058	$668,438	$282	$668,720	$35,834	5.7%	$27,663	4.3%	1
2	**Total Residential**			517,740	5,521,127	$628,518	$4,086	$632,604	$8,453	$641,058	$668,438	$282	$668,720	$35,834	5.7%	$27,663	4.3%	2
	Commercial & Industrial																	
3	Gen. Svc. < 31 kW	23	23	82,822	1,130,147	$126,081	$802	$126,883	$5,748	$132,631	$139,627	($151)	$139,476	$12,745	10.0%	$6,845	5.2%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,562	2,038,726	$186,682	$1,509	$188,191	$4,020	$192,212	$191,591	$6,813	$198,404	$3,399	1.8%	$6,192	3.2%	4
5	Gen. Svc. 201 - 999 kW	30	30	880	1,361,426	$110,812	$953	$111,765	$1,603	$113,368	$115,252	$1,752	$117,005	$3,487	3.1%	$3,637	3.2%	5
6	Large General Service >= 1,000 kW	48	48	195	3,079,837	$213,804	$1,940	$215,744	($8,589)	$207,155	$226,247	($3,452)	$222,795	$10,504	4.9%	$15,641	7.5%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	6	41,898	$5,249	$26	$5,275	($114)	$5,161	$5,571	($41)	$5,530	$296	4.9%	$370	7.5%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	1	0	$2,222	$0	$2,222	$12	$2,234	$2,116	$12	$2,128	($106)	8.4%	($106)	8.1%	8
9	Agricultural Pumping Service	41	41	7,894	221,554	$25,947	$160	$26,107	($1,115)	$24,992	$28,579	($1,277)	$27,302	$2,472	9.5%	$2,310	9.2%	9
10	**Total Commercial & Industrial**			102,360	7,873,589	$670,797	$5,390	$676,187	$1,565	$677,752	$708,984	$3,657	$712,641	$32,797	4.9%	$34,889	5.2%	10
	Lighting																	
11	Outdoor Area Lighting Service	15	15	6,045	8,693	$1,146	$5	$1,151	$214	$1,366	$1,127	($10)	$1,117	($24)	-2.1%	($249)	-18.2%	11
12	Street Lighting Service Comp. Owned	50,51,52	51	1,097	20,238	$3,220	$18	$3,238	$664	$3,902	$3,166	($31)	$3,134	($73)	-2.2%	($768)	-19.7%	12
13	Street Lighting Service Cust. Owned	53	53	302	12,046	$754	$3	$757	$154	$911	$742	($4)	$737	($16)	-2.1%	($174)	-19.1%	13
14	Recreational Field Lighting	54	54	105	1,457	$121	$1	$122	$24	$146	$119	($1)	$118	($3)	-2.4%	($28)	-19.1%	14
15	**Total Public Street Lighting**			7,549	42,434	$5,242	$27	$5,269	$1,056	$6,325	$5,153	($47)	$5,106	($116)	-2.2%	($1,218)	-19.3%	15
16	**Subtotal**			627,649	13,437,150	$1,304,557	$9,503	$1,314,060	$11,074	$1,325,134	$1,382,575	$3,892	$1,386,468	$68,515	5.2%	$61,333	4.6%	16
17	Employee Discount			*1,036*	*13,933*	($392)	($3)	($395)	($5)	($400)	($417)	($0)	($417)	($23)		($18)		17
18	AGA Revenue					$2,993		$2,993		$2,993	$2,993		$2,993	$0		$0		18
19	COOC Amortization					$1,727		$1,727		$1,727	$1,727		$1,727	$0		$0		19
20	**Total Sales with AGA**			627,649	13,437,150	$1,308,885	$9,501	$1,318,385	$11,069	$1,329,455	$1,386,878	$3,892	$1,390,770	$68,493	5.2%	$61,316	4.6%	20

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Table 1410-3
PACIFIC POWER
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2021

Line No.	Description	Pre Sch No.	Pro Sch No.	Pilot Cost Adj 95 ($000)	OCAT 104 ($000)	Tax Act 195 ($000)	Gen. Rem 197 ($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)
						PRO	PRO				PRE	PRO	PRE	PRO
	Residential													
1	Residential	4	4	$55	$2,601	($12,478)	$7,509	$276	$2,098	$221	$3,202	$0	$8,453	$282
2	**Total Residential**			$55	$2,601	($12,478)	$7,509	$276	$2,098	$221	$3,202	$0	$8,453	$282
	Commercial & Industrial													
3	Gen. Svc. < 31 kW	23	23	$11	$538	($2,656)	$1,458	$57	$407	$34	$4,701	$0	$5,748	($151)
4	Gen. Svc. 31 - 200 kW	28	28	$20	$779	($3,303)	$2,650	$102	$754	$61	$2,304	$5,749	$4,020	$6,813
5	Gen. Svc. 201 - 999 kW	30	30	$14	$459	($1,947)	$1,729	$68	$490	$41	$531	$899	$1,603	$1,752
6	Large General Service >= 1,000 kW	48	48	$31	$838	($3,850)	$3,665	$154	$986	$92	($10,690)	($5,368)	($8,589)	($3,452)
7	Partial Req. Svc. >= 1,000 kW	47	47	$0	$21	($52)	$50	$2	$13	$1	($152)	($76)	($114)	($41)
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	$3	$9	$0	$0	$0	$0	$0	$0	$0	$12	$12
9	Agricultural Pumping Service	41	41	$2	$101	($547)	$273	$11	$82	$7	($1,318)	($1,205)	($1,115)	($1,277)
10	**Total Commercial & Industrial**			$82	$2,745	($12,355)	$9,825	$394	$2,732	$236	($4,624)	($2)	$1,565	$3,657
	Lighting													
11	Outdoor Area Lighting Service	15	15	$0	$6	($23)	$4	$0	$3	$0	$206	$0	$214	($10)
12	Street Lighting Service Comp. Owned	50,51,52	51	$0	$16	($64)	$9	$1	$7	$1	$639	$0	$664	($31)
13	Street Lighting Service, Cust Owned	53	53	$0	$4	($15)	$5	$0	$1	$0	$148	$0	$154	($4)
14	Recreational Field Lighting	54	54	$0	$1	($2)	$1	$0	$0	$0	$23	$0	$24	($1)
15	**Total Public Street Lighting**			$0	$26	($105)	$18	$2	$11	$1	$1,016	$0	$1,056	($47)
16	**Subtotal**			$137	$5,372	($24,937)	$17,352	$671	$4,841	$458	($405)	($2)	$11,074	$3,892
17	Employee Discount			($0)	($2)	$8	($5)	($0)	($1)	($0)	($2)	$0	($5)	($0)
18	**Total**			$137	$5,370	($24,929)	$17,347	$671	$4,840	$458	($407)	($2)	$11,069	$3,892

Table 1410-4
PACIFIC POWER
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2021

Line No.	Description	Pre Sch No.	Pro Sch No.	Pilot Cost Adj 95 ¢/kWh	OCAT 104 ¢/kWh	Tax Act 195 ¢/kWh	Gen. Rem 197 ¢/kWh	RAC Defer. 203 ¢/kWh	Sol. Inctv. 204 ¢/kWh	Comm. Sol 207 ¢/kWh	RMA Sec 299 ¢/kWh	RMA Pri 299 ¢/kWh	RMA Trn 299 ¢/kWh	RMA Sec 299 ¢/kWh	RMA Pri 299 ¢/kWh	RMA Trn 299 ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
						PRO	PRO				PRE	PRE	PRE	PRO	PRO	PRO
	Residential															
1	Residential	4	4	0.001	0.41%	(0.226)	0.136	0.005	0.038	0.004	0.058			0.000		
	Commercial & Industrial															
2	Gen. Svc. < 31 kW	23	23	0.001	0.41%	(0.235)	0.129	0.005	0.036	0.003	0.416	0.416		0.000	0.000	
3	Gen. Svc. 31 - 200 kW	28	28	0.001	0.41%	(0.162)	0.130	0.005	0.037	0.003	0.113	0.113		0.282	0.282	
4	Gen. Svc. 201 - 999 kW	30	30	0.001	0.41%	(0.143)	0.127	0.005	0.036	0.003	0.039	0.039		0.066	0.066	
5	Large General Service >= 1,000 kW	48	48	0.001	0.41%	(0.125)	0.119	0.005	0.032	0.003	(0.267)	(0.334)	(0.413)	(0.134)	(0.168)	(0.207)
6	Partial Req. Svc. >= 1,000 kW	47	47	0.001	0.41%	(0.125)	0.119	0.005	0.032	0.003	(0.267)	(0.334)	(0.413)	(0.134)	(0.168)	(0.207)
7	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	0.001	0.41%	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	0.001	0.41%	(0.247)	0.123	0.005	0.037	0.003	(0.595)	(0.595)		(0.544)	(0.544)	
	Lighting															
9	Outdoor Area Lighting Service	15	15	0.001	0.41%	(0.261)	0.043	0.004	0.029	0.003	2.365			0.000		
10	Street Lighting Service HPS	50,51,52	51	0.001	0.41%	(0.318)	0.043	0.005	0.038	0.003	3.609			0.000		
11	Street Lighting Service	53	53	0.001	0.41%	(0.127)	0.043	0.002	0.012	0.001	1.230			0.000		
12	Recreational Field Lighting	54	54	0.001	0.41%	(0.159)	0.043	0.003	0.021	0.002	1.590			0.000		

Table 1410-5

PACIFIC POWER
PROPOSED REVISED FEDERAL TAX ADJUSTMENT - SCHEDULE 195
RATE SPREAD AND RATE CALCULATION
FORECAST 12 MONTHS ENDED DECEMBER 31, 2021

Line No.	Description	Pro Sch No.	No. of Cust	MWh	Proposed Revenues ($000) Base Rates	Remove NPC	Base Excl. NPC	Rate Spread	Proposed Schedule 195 Rates ¢/kWh	Credit ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
							(5) + (6)			
	Residential									
1	Residential	4	517,740	5,521,127	$668,438	($147,025)	$521,413	50.18%	(0.226)	($12,478)
2	**Total Residential**		517,740	5,521,127	$668,438	($147,025)	$521,413			($12,478)
	Commercial & Industrial									
3	Gen. Svc. < 31 kW	23	82,822	1,130,147	$139,627	($28,827)	$110,801	10.66%	(0.235)	($2,656)
4	Gen. Svc. 31 - 200 kW	28	10,562	2,038,726	$191,591	($53,535)	$138,056	13.29%	(0.162)	($3,303)
5	Gen. Svc. 201 - 999 kW	30	880	1,361,426	$115,252	($34,129)	$81,124	7.81%	(0.143)	($1,947)
6	Large General Service >= 1,000 kW	48	195	3,079,837	$226,247	($70,351)	$155,896	15.45%	(0.125)	($3,850)
7	Partial Req. Svc. >= 1,000 kW	47	6	41,898	$5,571	($899)	$4,672		(0.125)	($52)
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0	$2,116	$0	$2,116		-	$0
9	Agricultural Pumping Service	41	7,894	221,554	$28,579	($5,736)	$22,843	2.20%	(0.247)	($547)
10	**Total Commercial & Industrial**		102,360	7,873,589	$708,984	($193,476)	$515,508			($12,355)
	Lighting									
11	Outdoor Area Lighting Service	15	6,045	8,693	$1,127	($177)	$950	0.09%	(0.261)	($23)
12	Street Lighting Service HPS	51	1,097	20,238	$3,166	($476)	$2,689	0.26%	(0.318)	($64)
13	Street Lighting Service	53	302	12,046	$742	($104)	$638	0.06%	(0.127)	($15)
14	Recreational Field Lighting	54	105	1,457	$119	($22)	$97	0.01%	(0.159)	($2)
15	**Total Public Street Lighting**		7,549	42,434	$5,153	($779)	$4,374			($105)
16	**Subtotal**		627,649	13,437,150	$1,382,575	($341,280)	$1,041,295			($24,937)
17	Emplolyee Discount		*1,036*	*13,933*	($417)	$94	$94			$8
18	AGA Revenue				$2,993		$2,993			
19	COOC Amortization				$1,727		$1,727			
20	**Total Sales with AGA**		627,649	13,437,150	$1,385,151	($341,186)	$1,044,382			($24,929)

Table 1410-6

PACIFIC POWER
PROPOSED GENERATION PLANT REMOVAL ADJUSTMENT - NEW SCHEDULE 197
RATE SPREAD AND RATE CALCULATION
FORECAST 12 MONTHS ENDED DECEMBER 31, 2021

Line No.	Description	Pro Sch No.	No. of Cust	MWh	Generation Rate Spread	Proposed Schedule 197 Rates ¢/kWh	Proposed Schedule 197 Credit ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Residential						
1	Residential	4	517,740	5,521,127	43.44%	0.136	$7,509
2	**Total Residential**		517,740	5,521,127			$7,509
	Commercial & Industrial						
3	Gen. Svc. < 31 kW	23	82,822	1,130,147	8.43%	0.129	$1,458
4	Gen. Svc. 31 - 200 kW	28	10,562	2,038,726	15.32%	0.130	$2,650
5	Gen. Svc. 201 - 999 kW	30	880	1,361,426	9.98%	0.127	$1,729
6	Large General Service >= 1,000 kW	48	195	3,079,837	21.15%	0.119	$3,665
7	Partial Req. Svc. >= 1,000 kW	47	6	41,898		0.119	$50
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0		-	$0
9	Agricultural Pumping Service	41	7,894	221,554	1.58%	0.123	$273
10	**Total Commercial & Industrial**		102,360	7,873,589			$9,825
	Lighting						
11	Outdoor Area Lighting Service	15	6,045	8,693	0.02%	0.043	$4
12	Street Lighting Service HPS	51	1,097	20,238	0.05%	0.043	$9
13	Street Lighting Service	53	302	12,046	0.03%	0.043	$5
14	Recreational Field Lighting	54	105	1,457	0.00%	0.043	$1
15	**Total Public Street Lighting**		7,549	42,434			$18
16	**Subtotal**		627,649	13,437,150			$17,352
17	Emplolyee Discount		*1,036*	*13,933*			($5)
18	AGA Revenue						
19	COOC Amortization						
20	**Total Sales with AGA**		627,649	13,437,150			$17,347

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Single Family

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$20.29	$23.36	$3.07	15.13%
200	$30.04	$33.61	$3.57	11.88%
300	$39.82	$43.87	$4.05	10.17%
400	$49.58	$54.12	$4.54	9.16%
500	$59.35	$64.37	$5.02	8.46%
600	$69.12	$74.63	$5.51	7.97%
700	$78.87	$84.88	$6.01	7.62%
800	$88.66	$95.14	$6.48	7.31%
900	**$98.41**	**$105.39**	**$6.98**	**7.09%**
1,000	**$108.18**	**$115.65**	**$7.47**	**6.91%**
1,100	$120.93	$128.29	$7.36	6.09%
1,200	$133.66	$140.91	$7.25	5.42%
1,300	$146.41	$153.55	$7.14	4.88%
1,400	$159.14	$166.17	$7.03	4.42%
1,500	$171.89	$178.81	$6.92	4.03%
1,600	$184.63	$191.45	$6.82	3.69%
2,000	$235.59	$241.97	$6.38	2.71%
3,000	$363.00	$368.30	$5.30	1.46%
4,000	$490.42	$494.63	$4.21	0.86%
5,000	$617.83	$620.95	$3.12	0.50%

* Net rate including Schedules 91, 98, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Multi-Family

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$20.29	$18.19	($2.10)	-10.35%
200	$30.04	$28.44	($1.60)	-5.33%
300	$39.82	$38.70	($1.12)	-2.81%
400	$49.58	$48.94	($0.64)	-1.29%
500	$59.35	$59.20	($0.15)	-0.25%
600	**$69.12**	**$69.46**	**$0.34**	**0.49%**
700	$78.87	$79.71	$0.84	1.07%
800	$88.66	$89.97	$1.31	1.48%
900	$98.41	$100.22	$1.81	1.84%
1,000	$108.18	$110.48	$2.30	2.13%
1,100	$120.93	$123.11	$2.18	1.80%
1,200	$133.66	$135.74	$2.08	1.56%
1,300	$146.41	$148.38	$1.97	1.35%
1,400	$159.14	$161.00	$1.86	1.17%
1,500	$171.89	$173.64	$1.75	1.02%
1,600	$184.63	$186.28	$1.65	0.89%
2,000	$235.59	$236.80	$1.21	0.51%
3,000	$363.00	$363.13	$0.13	0.04%
4,000	$490.42	$489.45	($0.97)	-0.20%
5,000	$617.83	$615.78	($2.05)	-0.33%

* Net rate including Schedules 91, 98, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

		Monthly Billing*				Percent Difference	
		Present Price		Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$72	$81	$75	$84	3.84%	3.43%
	750	$99	$108	$103	$112	4.18%	3.85%
	1,000	$126	$135	$132	$140	4.40%	4.11%
	1,500	$180	$189	$188	$197	4.61%	4.40%
10	1,000	$126	$135	$132	$140	4.40%	4.11%
	2,000	$234	$243	$245	$254	4.73%	4.56%
	3,000	$342	$351	$359	$367	4.85%	4.73%
	4,000	$434	$443	$456	$465	5.08%	4.98%
20	4,000	$461	$470	$490	$499	6.30%	6.18%
	6,000	$644	$653	$684	$693	6.19%	6.11%
	8,000	$828	$837	$879	$887	6.13%	6.07%
	10,000	$1,011	$1,020	$1,073	$1,082	6.10%	6.04%
30	9,000	$974	$983	$1,044	$1,053	7.21%	7.14%
	12,000	$1,249	$1,258	$1,335	$1,344	6.93%	6.88%
	15,000	$1,524	$1,533	$1,627	$1,636	6.75%	6.71%
	18,000	$1,799	$1,808	$1,919	$1,927	6.62%	6.59%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

kW		Monthly Billing*				Percent	
		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$71	$79	$73	$82	3.66%	3.25%
	750	$97	$106	$101	$110	4.01%	3.67%
	1,000	$123	$132	$128	$137	4.20%	3.92%
	1,500	$176	$185	$184	$192	4.42%	4.20%
10	1,000	$123	$132	$128	$137	4.20%	3.92%
	2,000	$228	$237	$239	$248	4.53%	4.36%
	3,000	$334	$342	$349	$358	4.65%	4.53%
	4,000	$423	$432	$444	$452	4.87%	4.77%
20	4,000	$449	$458	$477	$486	6.10%	5.99%
	6,000	$628	$637	$666	$675	5.99%	5.90%
	8,000	$807	$816	$855	$864	5.92%	5.86%
	10,000	$986	$995	$1,044	$1,053	5.88%	5.83%
30	9,000	$949	$958	$1,016	$1,025	7.01%	6.94%
	12,000	$1,218	$1,227	$1,299	$1,308	6.72%	6.67%
	15,000	$1,486	$1,495	$1,583	$1,592	6.53%	6.49%
	18,000	$1,754	$1,763	$1,866	$1,875	6.40%	6.37%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	3,000	$351	$367	4.57%
	4,500	$464	$478	3.01%
	7,500	$689	$699	1.43%
31	6,200	$705	$735	4.23%
	9,300	$938	$964	2.73%
	15,500	$1,405	$1,422	1.21%
40	8,000	$904	$942	4.16%
	12,000	$1,205	$1,238	2.66%
	20,000	$1,808	$1,829	1.17%
60	12,000	$1,348	$1,405	4.22%
	18,000	$1,800	$1,849	2.70%
	30,000	$2,686	$2,727	1.54%
80	16,000	$1,786	$1,860	4.15%
	24,000	$2,381	$2,448	2.81%
	40,000	$3,558	$3,618	1.67%
100	20,000	$2,224	$2,315	4.11%
	30,000	$2,959	$3,046	2.94%
	50,000	$4,431	$4,508	1.76%
200	40,000	$4,355	$4,548	4.43%
	60,000	$5,826	$6,010	3.16%
	100,000	$8,768	$8,934	1.89%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$451	$469	3.89%
	6,000	$554	$567	2.26%
	7,500	$657	$664	1.13%
31	9,300	$906	$936	3.40%
	12,400	$1,118	$1,139	1.81%
	15,500	$1,331	$1,341	0.74%
40	12,000	$1,161	$1,200	3.29%
	16,000	$1,436	$1,461	1.72%
	20,000	$1,711	$1,722	0.65%
60	18,000	$1,732	$1,786	3.16%
	24,000	$2,137	$2,175	1.78%
	30,000	$2,540	$2,563	0.90%
80	24,000	$2,288	$2,362	3.22%
	32,000	$2,825	$2,879	1.90%
	40,000	$3,362	$3,396	1.00%
100	30,000	$2,842	$2,936	3.33%
	40,000	$3,513	$3,582	1.98%
	50,000	$4,184	$4,228	1.06%
200	60,000	$5,574	$5,773	3.58%
	80,000	$6,915	$7,065	2.16%
	100,000	$8,257	$8,357	1.20%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	20,000	$2,651	$2,746	3.60%
	30,000	$3,244	$3,329	2.65%
	50,000	$4,429	$4,496	1.51%
200	40,000	$4,660	$4,855	4.18%
	60,000	$5,846	$6,021	3.00%
	100,000	$8,217	$8,354	1.67%
300	60,000	$6,840	$7,160	4.67%
	90,000	$8,619	$8,910	3.38%
	150,000	$12,175	$12,409	1.92%
400	80,000	$8,902	$9,343	4.96%
	120,000	$11,273	$11,676	3.58%
	200,000	$16,015	$16,342	2.04%
500	100,000	$10,994	$11,550	5.06%
	150,000	$13,958	$14,467	3.64%
	250,000	$19,886	$20,299	2.08%
600	120,000	$13,086	$13,757	5.13%
	180,000	$16,643	$17,257	3.69%
	300,000	$23,756	$24,256	2.10%
800	160,000	$17,271	$18,171	5.21%
	240,000	$22,013	$22,837	3.74%
	400,000	$31,497	$32,169	2.13%
1000	200,000	$21,455	$22,585	5.27%
	300,000	$27,383	$28,418	3.78%
	500,000	$39,238	$40,083	2.15%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	30,000	$3,181	$3,301	3.78%
	40,000	$3,763	$3,877	3.03%
	50,000	$4,344	$4,452	2.48%
200	60,000	$5,736	$5,968	4.03%
	80,000	$6,900	$7,118	3.17%
	100,000	$8,063	$8,269	2.56%
300	90,000	$8,452	$8,825	4.42%
	120,000	$10,197	$10,551	3.48%
	150,000	$11,942	$12,278	2.81%
400	120,000	$11,073	$11,568	4.48%
	160,000	$13,399	$13,870	3.51%
	200,000	$15,725	$16,171	2.84%
500	150,000	$13,705	$14,328	4.54%
	200,000	$16,613	$17,205	3.56%
	250,000	$19,522	$20,082	2.87%
600	180,000	$16,338	$17,087	4.58%
	240,000	$19,828	$20,539	3.59%
	300,000	$23,318	$23,992	2.89%
800	240,000	$21,604	$22,606	4.64%
	320,000	$26,257	$27,209	3.63%
	400,000	$30,910	$31,812	2.92%
1000	300,000	$26,870	$28,124	4.67%
	400,000	$32,686	$33,879	3.65%
	500,000	$38,502	$39,633	2.94%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	2,000	$194	$222	$155	$207	$220	$197	6.90%	-0.87%	26.67%
	3,000	$291	$319	$155	$311	$324	$197	6.90%	1.49%	26.67%
	5,000	$485	$513	$155	$518	$531	$197	6.90%	3.54%	26.67%
Three Phase										
20	4,000	$388	$444	$310	$415	$440	$393	6.90%	-0.88%	26.66%
	6,000	$582	$638	$310	$622	$647	$393	6.90%	1.49%	26.66%
	10,000	$970	$1,026	$310	$1,037	$1,062	$393	6.90%	3.54%	26.66%
100	20,000	$1,940	$2,218	$1,355	$2,074	$2,198	$1,748	6.90%	-0.88%	29.01%
	30,000	$2,910	$3,188	$1,355	$3,111	$3,235	$1,748	6.90%	1.49%	29.01%
	50,000	$4,850	$5,128	$1,355	$5,184	$5,309	$1,748	6.90%	3.54%	29.01%
300	60,000	$5,820	$6,654	$3,410	$6,221	$6,595	$4,420	6.90%	-0.88%	29.60%
	90,000	$8,730	$9,564	$3,410	$9,332	$9,706	$4,420	6.90%	1.49%	29.60%
	150,000	$14,549	$15,383	$3,410	$15,553	$15,927	$4,420	6.90%	3.54%	29.60%

* Net rate including Schedules 91, 98, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December- March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December- March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December- March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$282	$309	$155	$301	$313	$186	6.84%	1.42%	20.00%
	4,000	$376	$403	$155	$402	$414	$186	6.85%	2.69%	20.00%
	5,000	$470	$497	$155	$502	$514	$186	6.84%	3.48%	20.00%
Three Phase										
20	6,000	$564	$618	$310	$603	$626	$372	6.84%	1.43%	20.00%
	8,000	$752	$426	$310	$803	$827	$372	6.84%	94.38%	20.00%
	10,000	$940	$426	$310	$1,004	$1,028	$372	6.84%	141.56%	20.00%
100	30,000	$2,820	$3,088	$1,344	$3,013	$3,132	$1,737	6.84%	1.43%	29.23%
	40,000	$3,759	$4,028	$1,344	$4,017	$4,137	$1,737	6.84%	2.69%	29.23%
	50,000	$4,699	$4,968	$1,344	$5,021	$5,141	$1,737	6.84%	3.48%	29.23%
300	90,000	$8,459	$9,265	$3,400	$9,038	$9,397	$4,409	6.84%	1.43%	29.69%
	120,000	$11,278	$12,084	$3,400	$12,050	$12,410	$4,409	6.84%	2.69%	29.69%
	150,000	$14,098	$14,904	$3,400	$15,063	$15,422	$4,409	6.84%	3.48%	29.69%

* Net rate including Schedules 91, 98, 290 and 297.

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		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$26,660	$30,099	12.90%
	500,000	$37,985	$41,394	8.98%
	700,000	$49,309	$52,690	6.86%
2,000	600,000	$52,887	$59,535	12.57%
	1,000,000	$73,285	$79,877	8.99%
	1,400,000	$94,833	$101,368	6.89%
6,000	1,800,000	$153,423	$172,812	12.64%
	3,000,000	$218,069	$237,285	8.81%
	4,200,000	$282,714	$301,758	6.74%
12,000	3,600,000	$305,520	$343,862	12.55%
	6,000,000	$434,810	$472,808	8.74%
	8,400,000	$564,101	$601,755	6.68%

Notes:	Present	Proposed
On-Peak kWh	62.84%	35.98%
Off-Peak kWh	37.16%	64.02%

* Net rate including Schedules 91 and 290. Schedule 297 included for kWh levels under 730,000.

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 Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$25,244	$27,847	10.31%
	500,000	$35,775	$38,442	7.45%
	700,000	$46,305	$49,036	5.90%
2,000	600,000	$50,013	$55,063	10.10%
	1,000,000	$68,824	$74,002	7.52%
	1,400,000	$88,784	$94,091	5.98%
6,000	1,800,000	$144,399	$159,365	10.36%
	3,000,000	$204,281	$219,631	7.51%
	4,200,000	$264,164	$279,897	5.96%
12,000	3,600,000	$287,439	$317,092	10.32%
	6,000,000	$407,204	$437,624	7.47%
	8,400,000	$526,969	$558,156	5.92%

Notes:	Present	Proposed
On-Peak kWh	60.07%	35.98%
Off-Peak kWh	39.93%	64.02%

* Net rate including Schedules 91 and 290. Schedule 297 included for kWh levels under 730,000.

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 Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	500,000	$35,525	$36,950	4.01%
	700,000	$45,343	$47,052	3.77%
2,000	1,000,000	$67,910	$70,803	4.26%
	1,400,000	$86,446	$89,906	4.00%
6,000	3,000,000	$201,717	$210,436	4.32%
	4,200,000	$257,323	$267,744	4.05%
12,000	6,000,000	$401,279	$418,800	4.37%
	8,400,000	$512,492	$533,417	4.08%

Notes:	Present	Proposed
On-Peak kWh	56.54%	33.29%
Off-Peak kWh	43.46%	66.71%

* Net rate including Schedules 91 and 290. Schedule 297 included for kWh levels under 730,000.

Docket No. UE 374
Exhibit PAC/1411
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Residential Basic Charge Calculation

February 2020

Pacific Power
State of Oregon
Residential Basic Charge Calculation
20 Year Residential Marginal Unit Costs
December 2021 Dollars per Customer per Year

	All Residential	Single Family	Multi-Family
Poles	$77.80	$90.15	$29.79
Conductor	$41.61	$48.22	$15.93
Transformers	$90.81	$108.46	$30.76
Service Drop	$77.37	$77.37	$77.37
Meters	$24.63	$24.63	$24.63
Meter Reading	$0.00	$0.00	$0.00
Billing & Collections	$28.14	$28.14	$28.14
Uncollectables	$8.52	$8.52	$8.52
Customer Service / Other	$8.26	$8.26	$8.26
Total per Year	$357.13	$393.75	$223.40
Total per Month	$29.76	$32.81	$18.62
Multi-Family to Single-Family Differential			57%
Current Basic Charge	$9.50		
10% Movement Towards Cost		$11.83	
57% Applied to Multi-Family			$6.71
Proposed Basic Charge		**$12.00**	**$7.00**

Docket No. UE 374
Exhibit PAC/1412
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Time of Use Period Justification

February 2020

Pacific Power
State of Oregon
Resource Value of Solar Energy Price (EIM Prices for 36 Months Ended October 2019)- Pacific Time

All Days Month	**HE** 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	**Monthly Average**	**Rank**
1	17.85	16.94	16.78	17.39	18.05	20.68	23.69	25.98	21.15	19.47	18.26	16.32	14.95	14.68	15.34	17.46	22.43	28.12	25.81	24.37	24.98	23.73	19.84	18.08	20.10	4
2	17.45	15.60	15.62	16.20	18.20	22.71	29.40	27.17	19.29	16.06	13.30	11.23	10.36	10.49	9.19	12.12	18.25	32.35	36.67	29.55	24.63	21.66	19.75	17.15	19.35	6
3	15.29	14.43	14.04	14.82	15.77	20.73	24.49	26.15	19.25	16.91	12.20	9.89	10.50	7.68	7.57	8.04	10.30	17.16	24.70	30.98	26.89	22.19	20.27	16.77	16.96	9
4	13.03	11.57	10.48	10.56	12.09	19.04	20.13	18.38	15.10	11.59	9.09	8.12	8.33	7.90	8.21	9.55	9.09	12.19	21.31	32.90	31.28	19.09	18.13	14.33	14.64	10
5	14.78	10.57	8.76	8.62	10.70	14.46	14.14	13.66	11.41	10.95	10.70	9.57	9.57	10.84	10.71	12.54	13.93	13.48	18.18	22.23	24.30	21.04	21.41	18.64	13.97	12
6	13.43	11.87	10.67	9.58	10.74	11.96	8.38	11.31	12.44	11.98	13.18	13.77	14.29	18.94	15.65	16.51	16.40	16.80	17.59	17.78	16.92	16.56	16.90	14.57	14.09	11
7	26.97	24.98	24.11	23.26	24.12	24.71	20.60	22.78	24.02	25.50	28.13	29.20	29.56	31.92	34.48	37.23	37.43	34.58	36.66	37.29	34.37	32.42	31.74	27.82	29.33	3
8	27.12	25.16	23.75	22.85	23.46	25.76	22.64	23.94	23.80	25.44	27.71	29.28	30.44	33.57	37.00	40.12	46.06	51.91	61.70	53.00	41.46	35.47	33.02	28.87	33.06	1
9	27.51	26.01	25.13	24.79	25.64	28.91	28.14	29.47	27.11	26.81	27.38	27.99	28.68	30.71	32.57	33.62	33.62	35.68	42.24	44.89	37.02	33.01	32.80	29.00	30.78	2
10	15.26	14.28	14.37	13.98	14.88	17.96	20.27	25.67	17.12	14.46	13.38	13.04	13.34	13.81	13.95	14.72	16.92	29.72	37.38	27.16	21.32	19.56	19.10	15.97	18.23	7
11	15.73	14.66	14.33	14.94	15.86	19.23	21.02	23.47	17.31	14.94	13.81	13.41	12.70	12.46	14.11	17.98	25.36	26.31	22.63	20.80	20.31	19.79	19.25	17.50	17.83	8
12	17.87	17.29	16.72	17.07	18.00	20.09	22.10	26.62	25.01	19.26	18.01	15.78	14.70	14.48	15.52	18.33	23.62	25.82	24.29	23.13	22.83	21.76	20.47	18.18	19.87	5

Annual Average Prices

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$/MWh	18.52	16.95	16.23	16.17	17.29	20.52	21.25	22.88	19.42	17.78	17.10	16.47	16.45	17.29	17.86	19.85	22.78	27.01	30.76	30.34	27.19	23.86	22.72	19.74
Rank	14	20	23	24	18	10	9	6	13	16	19	21	22	17	15	11	7	4	1	2	3	5	8	12

Summer (July-Sept) Average Prices

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$/MWh	27.20	25.38	24.33	23.63	24.40	26.46	23.79	25.39	24.98	25.91	27.74	28.82	29.56	32.07	34.68	36.99	39.03	40.72	46.87	45.06	37.61	33.63	32.52	28.56
Rank	15	19	22	24	21	16	23	18	20	17	14	12	11	10	7	6	4	3	1	2	5	8	9	13

Winter (Oct-Jun) Average Prices

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$/MWh	15.63	14.13	13.53	13.68	14.92	18.54	20.40	22.05	17.56	15.07	13.55	12.35	12.08	12.37	12.25	14.14	17.37	22.44	25.40	25.43	23.72	20.60	19.46	16.80
Rank	13	17	20	18	15	9	7	5	10	14	19	22	24	21	23	16	11	4	2	1	3	6	8	12

Pacific Power
State of Oregon
Residential Time of Use Pilot - Proposed Schedule 6 - Pacific Time

All Days

Month \ **HE**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	17.85	16.94	16.78	17.39	18.05	20.68	23.69	25.98	21.15	19.47	18.26	16.32	14.95	14.68	15.34	17.46	22.43	28.12	25.81	24.37	24.98	23.73	19.84	18.08
2	17.45	15.60	15.62	16.20	18.20	22.71	29.40	27.17	19.29	16.06	13.30	11.23	10.36	10.49	9.19	12.12	18.25	32.35	36.67	29.55	24.63	21.66	19.75	17.15
3	15.29	14.43	14.04	14.82	15.77	20.73	24.49	26.15	19.25	16.91	12.20	9.89	10.50	7.68	7.57	8.04	10.30	17.16	24.70	30.98	26.89	22.19	20.27	16.77
4	13.03	11.57	10.48	10.56	12.09	19.04	20.13	18.38	15.10	11.59	9.09	8.12	8.33	7.90	8.21	9.55	9.09	12.19	21.31	32.90	31.28	19.09	18.13	14.33
5	14.78	10.57	8.76	8.62	10.70	14.46	14.14	13.66	11.41	10.95	10.70	9.57	9.57	10.84	10.71	12.54	13.93	13.48	18.18	22.23	24.30	21.04	21.41	18.64
6	13.43	11.87	10.67	9.58	10.74	11.96	8.38	11.31	12.44	11.98	13.18	13.77	14.29	18.94	15.65	16.51	16.40	16.80	17.59	17.78	16.92	16.56	16.90	14.57
7	26.97	24.98	24.11	23.26	24.12	24.71	20.60	22.78	24.02	25.50	28.13	29.20	29.56	31.92	34.48	37.23	37.43	34.58	36.66	37.29	34.37	32.42	31.74	27.82
8	27.12	25.16	23.75	22.85	23.46	25.76	22.64	23.94	23.80	25.44	27.71	29.28	30.44	33.57	37.00	40.12	46.06	51.91	61.70	53.00	41.46	35.47	33.02	28.87
9	27.51	26.01	25.13	24.79	25.64	28.91	28.14	29.47	27.11	26.81	27.38	27.99	28.68	30.71	32.57	33.62	33.62	35.68	42.24	44.89	37.02	33.01	32.80	29.00
10	15.26	14.28	14.37	13.98	14.88	17.96	20.27	25.67	17.12	14.46	13.38	13.04	13.34	13.81	13.95	14.72	16.92	29.72	37.38	27.16	21.32	19.56	19.10	15.97
11	15.73	14.66	14.33	14.94	15.86	19.23	21.02	23.47	17.31	14.94	13.81	13.41	12.70	12.46	14.11	17.98	25.36	26.31	22.63	20.80	20.31	19.79	19.25	17.50
12	17.87	17.29	16.72	17.07	18.00	20.09	22.10	26.62	25.01	19.26	18.01	15.78	14.70	14.48	15.52	18.33	23.62	25.82	24.29	23.13	22.83	21.76	20.47	18.18

Summer (July-Sept) Average Prices **Top 6 Hours**

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$/MWh	27.20	25.38	24.33	23.63	24.40	26.46	23.79	25.39	24.98	25.91	27.74	28.82	29.56	32.07	34.68	36.99	39.03	40.72	46.87	45.06	37.61	33.63	32.52	28.56
Rank	15	19	22	24	21	16	23	18	20	17	14	12	11	10	7	6	4	3	1	2	5	8	9	13

On-Peak = 3pm - 9pm

Winter (Oct-Jun) Average Prices **Top 8 Hours**

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$/MWh	15.63	14.13	13.53	13.68	14.92	18.54	20.40	22.05	17.56	15.07	13.55	12.35	12.08	12.37	12.25	14.14	17.37	22.44	25.40	25.43	23.72	20.60	19.46	16.80
Rank	13	17	20	18	15	9	7	5	10	14	19	22	24	21	23	16	11	4	2	1	3	6	8	12

On-Peak = 6am-8am; 5pm-11pm

Pacific Power
State of Oregon
Agricultural Pumping Service Time of Use Options - Schedule 41 - Pacific Time

All Days

Month \ **HE**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	17.85	16.94	16.78	17.39	18.05	20.68	23.69	25.98	21.15	19.47	18.26	16.32	14.95	14.68	15.34	17.46	22.43	28.12	25.81	24.37	24.98	23.73	19.84	18.08
2	17.45	15.60	15.62	16.20	18.20	22.71	29.40	27.17	19.29	16.06	13.30	11.23	10.36	10.49	9.19	12.12	18.25	32.35	36.67	29.55	24.63	21.66	19.75	17.15
3	15.29	14.43	14.04	14.82	15.77	20.73	24.49	26.15	19.25	16.91	12.20	9.89	10.50	7.68	7.57	8.04	10.30	17.16	24.70	30.98	26.89	22.19	20.27	16.77
4	13.03	11.57	10.48	10.56	12.09	19.04	20.13	18.38	15.10	11.59	9.09	8.12	8.33	7.90	8.21	9.55	9.09	12.19	21.31	32.90	31.28	19.09	18.13	14.33
5	14.78	10.57	8.76	8.62	10.70	14.46	14.14	13.66	11.41	10.95	10.70	9.57	9.57	10.84	10.71	12.54	13.93	13.48	18.18	22.23	24.30	21.04	21.41	18.64
6	13.43	11.87	10.67	9.58	10.74	11.96	8.38	11.31	12.44	11.98	13.18	13.77	14.29	18.94	15.65	16.51	16.40	16.80	17.59	17.78	16.92	16.56	16.90	14.57
7	26.97	24.98	24.11	23.26	24.12	24.71	20.60	22.78	24.02	25.50	28.13	29.20	29.56	31.92	34.48	37.23	37.43	34.58	36.66	37.29	34.37	32.42	31.74	27.82
8	27.12	25.16	23.75	22.85	23.46	25.76	22.64	23.94	23.80	25.44	27.71	29.28	30.44	33.57	37.00	40.12	46.06	51.91	61.70	53.00	41.46	35.47	33.02	28.87
9	27.51	26.01	25.13	24.79	25.64	28.91	28.14	29.47	27.11	26.81	27.38	27.99	28.68	30.71	32.57	33.62	33.62	35.68	42.24	44.89	37.02	33.01	32.80	29.00
10	15.26	14.28	14.37	13.98	14.88	17.96	20.27	25.67	17.12	14.46	13.38	13.04	13.34	13.81	13.95	14.72	16.92	29.72	37.38	27.16	21.32	19.56	19.10	15.97
11	15.73	14.66	14.33	14.94	15.86	19.23	21.02	23.47	17.31	14.94	13.81	13.41	12.70	12.46	14.11	17.98	25.36	26.31	22.63	20.80	20.31	19.79	19.25	17.50
12	17.87	17.29	16.72	17.07	18.00	20.09	22.10	26.62	25.01	19.26	18.01	15.78	14.70	14.48	15.52	18.33	23.62	25.82	24.29	23.13	22.83	21.76	20.47	18.18

Summer (July-Sept) Average Prices **Top 6 Hours**

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$/MWh	27.20	25.38	24.33	23.63	24.40	26.46	23.79	25.39	24.98	25.91	27.74	28.82	29.56	32.07	34.68	36.99	39.03	40.72	46.87	45.06	37.61	33.63	32.52	28.56
Rank	15	19	22	24	21	16	23	18	20	17	14	12	11	10	7	6	4	3	1	2	5	8	9	13

Option A On-Peak = 2pm - 6pm
On- to Off-Peak 8.16
$/MWh difference

Option B On-Peak = 6pm - 10pm
On- to Off-Peak 11.69
$/MWh difference

Average of Option A and Option B
On- to Off-Peak $\boxed{9.92}$
$/MWh difference

Pacific Power
State of Oregon
Schedule 48 Time of Use - Pacific Time

All Days

Month \ **HE**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	17.85	16.94	16.78	17.39	18.05	20.68	23.69	25.98	21.15	19.47	18.26	16.32	14.95	14.68	15.34	17.46	22.43	28.12	25.81	24.37	24.98	23.73	19.84	18.08
2	17.45	15.60	15.62	16.20	18.20	22.71	29.40	27.17	19.29	16.06	13.30	11.23	10.36	10.49	9.19	12.12	18.25	32.35	36.67	29.55	24.63	21.66	19.75	17.15
3	15.29	14.43	14.04	14.82	15.77	20.73	24.49	26.15	19.25	16.91	12.20	9.89	10.50	7.68	7.57	8.04	10.30	17.16	24.70	30.98	26.89	22.19	20.27	16.77
4	13.03	11.57	10.48	10.56	12.09	19.04	20.13	18.38	15.10	11.59	9.09	8.12	8.33	7.90	8.21	9.55	9.09	12.19	21.31	32.90	31.28	19.09	18.13	14.33
5	14.78	10.57	8.76	8.62	10.70	14.46	14.14	13.66	11.41	10.95	10.70	9.57	9.57	10.84	10.71	12.54	13.93	13.48	18.18	22.23	24.30	21.04	21.41	18.64
6	13.43	11.87	10.67	9.58	10.74	11.96	8.38	11.31	12.44	11.98	13.18	13.77	14.29	18.94	15.65	16.51	16.40	16.80	17.59	17.78	16.92	16.56	16.90	14.57
7	26.97	24.98	24.11	23.26	24.12	24.71	20.60	22.78	24.02	25.50	28.13	29.20	29.56	31.92	34.48	37.23	37.43	34.58	36.66	37.29	34.37	32.42	31.74	27.82
8	27.12	25.16	23.75	22.85	23.46	25.76	22.64	23.94	23.80	25.44	27.71	29.28	30.44	33.57	37.00	40.12	46.06	51.91	61.70	53.00	41.46	35.47	33.02	28.87
9	27.51	26.01	25.13	24.79	25.64	28.91	28.14	29.47	27.11	26.81	27.38	27.99	28.68	30.71	32.57	33.62	33.62	35.68	42.24	44.89	37.02	33.01	32.80	29.00
10	15.26	14.28	14.37	13.98	14.88	17.96	20.27	25.67	17.12	14.46	13.38	13.04	13.34	13.81	13.95	14.72	16.92	29.72	37.38	27.16	21.32	19.56	19.10	15.97
11	15.73	14.66	14.33	14.94	15.86	19.23	21.02	23.47	17.31	14.94	13.81	13.41	12.70	12.46	14.11	17.98	25.36	26.31	22.63	20.80	20.31	19.79	19.25	17.50
12	17.87	17.29	16.72	17.07	18.00	20.09	22.10	26.62	25.01	19.26	18.01	15.78	14.70	14.48	15.52	18.33	23.62	25.82	24.29	23.13	22.83	21.76	20.47	18.18

Summer (July-Sept) Average Prices **Top 10 Hours**

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$/MWh	27.20	25.38	24.33	23.63	24.40	26.46	23.79	25.39	24.98	25.91	27.74	28.82	29.56	32.07	34.68	36.99	39.03	40.72	46.87	45.06	37.61	33.63	32.52	28.56
Rank	15	19	22	24	21	16	23	18	20	17	14	12	11	10	7	6	4	3	1	2	5	8	9	13

On-Peak = 1pm - 11pm

Winter (Oct-Jun) Average Prices **Top 12 Hours**

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$/MWh	15.63	14.13	13.53	13.68	14.92	18.54	20.40	22.05	17.56	15.07	13.55	12.35	12.08	12.37	12.25	14.14	17.37	22.44	25.40	25.43	23.72	20.60	19.46	16.80
Rank	13	17	20	18	15	9	7	5	10	14	19	22	24	21	23	16	11	4	2	1	3	6	8	12

On-Peak = 5am-9am; 4pm-12am (midnight)

On- to Off-Peak Scalar 7.39

Docket No. UE 374
Exhibit PAC/1413
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Schedule 6 Residential Time of Use Pilot Program Rates

February 2020

PACIFIC POWER
State of Oregon
Proposed Residential Time- of-Use Pilot Program Rates

Forecast 12 Months Ended December 31, 2021

Schedule	Forecast 1/21 - 12/21 Units		Proposed Schedule 4 Price		Proposed Schedule 4 Dollars	Proposed Schedule 6 Price		Proposed Schedule 6 Dollars
Schedule No. 4								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	5,521,126,670	kWh	0.820	¢	$45,273,239	0.820	¢	$45,273,239
System Usage Charge								
Sch 200 related, per kWh	5,521,126,670	kWh	0.084	¢	$4,637,746	0.084	¢	$4,637,746
T&A and Sch 201 related, per kWh	5,521,126,670	kWh	0.077	¢	$4,251,268	0.077	¢	$4,251,268
Distribution Charge								
Basic Charge Single Family, per month	4,984,042	bill	$12.00		$59,808,504	$12.00		$59,808,504
Basic Charge Multi Family, per month	1,228,844	bill	$7.00		$8,601,908	$7.00		$8,601,908
Total Bills	6,212,885	bill						
Three Phase Demand Charge, per kW demand	15,565	kW	$2.20		$34,243	$2.20		$34,243
Three Phase Minimum Demand Charge, per month	1,443	bill	$3.80		$5,483	$3.80		$5,483
Distribution Energy Charge, per kWh	5,521,126,670	kWh	3.822	¢	$211,017,461	3.822	¢	$211,017,461
Energy Charge - Schedule 200								
First Block kWh (0-1,000)	4,171,965,406	kWh	3.279	¢	$136,798,746			
Second Block kWh (> 1,000)	1,349,161,264	kWh	3.779	¢	$50,984,804			
All kWh	5,521,126,670		3.401			3.401	¢	$187,783,550
Subtotal	5,521,126,670	kWh			$521,413,402			$521,413,402
Schedule 201								
First Block kWh (0-1,000)	4,171,965,406	kWh	2.444	¢	$101,962,835			
Second Block kWh (> 1,000)	1,349,161,264	kWh	3.340	¢	$45,061,986			
All kWh	5,521,126,670					2.663	¢	$147,024,821
On-Peak Adder, per On-Peak kWh	2,071,633,484					7.050	¢	$146,050,161
Off-Peak Adder, per Off-Peak kWh	3,449,493,186					-4.234	¢	($146,050,161)
Total	5,521,126,670	kWh			$668,438,223			$668,438,223
Total On-Peak kWh rate						**17.917**	**¢**	
Total Off-Peak kWh rate						**6.633**	**¢**	
On/off Differential						***2.7011***		
On/off Cents per kWh Difference						11.284	¢	

Schedule 6 TOU definition
Summer (July - September) On-Peak: All Days 3pm to 9pm
Non-Summer (October - June) On-Peak: All Days 6am to 8am and 5pm to 11pm
Off-Peak: All other hours

Docket No. UE 374
Exhibit PAC/1414
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Schedule 41 Agricultural Pumping Service Time of Use Option Rates

February 2020

PACIFIC POWER
State of Oregon
Proposed Irrigation Time-of-Use Optional Rates

Forecast 12 Months Ended December 31, 2021

Schedule	Forecast 1/21 - 12/21 Units		Proposed non-TOU Price	Proposed non-TOU Dollars	Proposed TOU Price	Proposed TOU Dollars
Schedule No. 41/741 - Irrigation						
Agricultural Pumping Service (Secondary)						
Transmission & Ancillary Services Charge						
per kWh	221,514,932	kWh	0.645 ¢	$1,428,771	0.645 ¢	$1,428,771
System Usage Charge						
Sch 200 related, per kWh	221,514,932	kWh	0.074 ¢	$163,921	0.074 ¢	$163,921
T&A and Sch 201 related, per kWh	221,514,932	kWh	0.096 ¢	$212,654	0.096 ¢	$212,654
Distribution Charge						
Basic Charge (billed in November)						
Load Size≤ 50 kW, or Single Phase Any Size	6,698	bill	No Charge		No Charge	
Three Phase Load Size 51 - 300 kW, per customer	1,169	bill	$390.00	$455,910	$390.00	$455,910
Three Phase Load Size > 300 kW, per customer	25	bill	$1,530.00	$38,250	$1,530.00	$38,250
Total Customers	7,892	bill				
Monthly Bills	57,612					
Load Size Charge (billed in November)						
Single Phase Any Size, Three Phase≤ 50 kW	113,352	kW	$19.00	$2,153,688	$19.00	$2,153,688
Three Phase Load Size 51-300 kW, per kW	98,028	kW	$13.00	$1,274,364	$13.00	$1,274,364
Three Phase Load Size > 300 kW, per kW	10,314	kW	$8.00	$82,512	$8.00	$82,512
Single Phase, Minimum Charge	505	bill	$70.00	$35,350	$70.00	$35,350
Three Phase, Minimum Charge	1,482	bill	$115.00	$170,430	$115.00	$170,430
Distribution Energy Charge, per kWh	221,514,932	kWh	4.464 ¢	$9,888,427	4.464 ¢	$9,888,427
Reactive Power Charge, per kvar	191,933	kvar	65.00 ¢	$124,756	65.00 ¢	$124,756
Energy Charge - Schedule 200						
Winter, 1st 100 kWh/kW, per kWh	2,534,777	kWh	3.074 ¢	$77,919	3.074 ¢	$77,919
Winter, All additional kWh, per kWh	1,878,032	kWh	3.074 ¢	$57,731	3.074 ¢	$57,731
Summer, All kWh, per kWh	217,102,123	kWh	3.074 ¢	$6,673,719	3.074 ¢	$6,673,719
Subtotal				$22,838,402		$22,838,402
Schedule 201						
Winter, 1st 100 kWh/kW, per kWh	2,534,777	kWh	3.781 ¢	$95,840		
Winter, All additional kWh, per kWh	1,878,032	kWh	2.575 ¢	$48,359		
Summer, All kWh, per kWh	217,102,123	kWh	2.575 ¢	$5,590,380		
All kWh	221,514,932	kWh			2.589 ¢	$5,735,022
Option A Summer On Peak Adder, per On-peak kWh	10,649,201	kWh			4.989 ¢	$531,236
Option B Summer On Peak Adder, per On-peak kWh	10,414,959	kWh			4.989 ¢	$519,551
Summer Off Peak Adder, per Off-peak kWh	105,970,805	kWh			-0.992 ¢	($1,051,230)
Total	221,514,932	kWh		$28,572,981		$28,572,981
Schedule No. 41/741 - Irrigation						
Agricultural Pumping Service (Primary)						
Transmission & Ancillary Services Charge						
per kWh	39,449	kWh	0.627 ¢	$247	0.627 ¢	$247
System Usage Charge						
Sch 200 related, per kWh	39,449	kWh	0.072 ¢	$28	0.072 ¢	$28
T&A and Sch 201 related, per kWh	39,449	kWh	0.093 ¢	$37	0.093 ¢	$37
Distribution Charge						
Basic Charge (billed in November)						
Load Size≤ 50 kW, or Single Phase Any Size	1	bill	No Charge		No Charge	
Three Phase Load Size 51 - 300 kW, per customer	1	bill	$380.00	$380	$380.00	$380
Three Phase Load Size > 300 kW, per customer	0	bill	$1,490.00	$0	$1,490.00	$0
Total Customers	2	bill				
Monthly Bills	20					
Load Size Charge (billed in November)						
Single Phase Any Size, Three Phase≤ 50 kW	11	kW	$18.00	$198	$18.00	$198
Three Phase Load Size 51-300 kW, per kW	83	kW	$13.00	$1,079	$13.00	$1,079
Three Phase Load Size > 300 kW, per kW	0	kW	$8.00	$0	$8.00	$0
Single Phase, Minimum Charge	0	bill	$70.00	$0	$70.00	$0
Three Phase, Minimum Charge	0	bill	$110.00	$0	$110.00	$0
Distribution Energy Charge, per kWh	39,449	kWh	4.338 ¢	$1,711	4.338 ¢	$1,711
Reactive Power Charge, per kvar	57	kvar	60.00 ¢	$34	60.00 ¢	$34
Energy Charge - Schedule 200						
Winter, 1st 100 kWh/kW, per kWh	546	kWh	2.987 ¢	$16	2.987 ¢	$16
Winter, All additional kWh, per kWh	0	kWh	2.987 ¢	$0	2.987 ¢	$0
Summer, All kWh, per kWh	38,903	kWh	2.987 ¢	$1,162	2.987 ¢	$1,162
Subtotal	39,449	kWh		$4,892		$4,892
Schedule 201						
Winter, 1st 100 kWh/kW, per kWh	546	kWh	3.653 ¢	$20		
Winter, All additional kWh, per kWh	0	kWh	2.495 ¢	$0		
Summer, All kWh, per kWh	38,903	kWh	2.495 ¢	$971		
All kWh	39,449	kWh			2.512 ¢	$991
Option A Summer On Peak Adder, per On-peak kWh	1,896	kWh			4.989 ¢	$95
Option B Summer On Peak Adder, per On-peak kWh	1,855	kWh			4.989 ¢	$93
Summer Off Peak Adder, per Off-peak kWh	18,872	kWh			-0.992 ¢	($187)
Total	39,449	kWh		$5,883		$5,884
Total On-Peak kWh rate (Secondary)					**15.931 ¢**	
Total Off-Peak kWh rate (Secondary)					**9.950 ¢**	
On/off Differential					*1.6011*	
On/off Cents per kWh Difference					**5.981 ¢**	

Schedule 41 TOU definition
Option A Summer (July - September) On-Peak: All Days 2pm to 6pm
Option B Summer (July - September) On-Peak: All Days 6pm to 10pm
Off-Peak: All Summer hours that are not On-Peak
Non-Summer months (October - June) have no TOU periods or rate adders.

Docket No. UE 374
Exhibit PAC/1415
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Schedule 29 General Service Time of Use Pilot Rates

February 2020

PACIFIC POWER
State of Oregon
Proposed General Service Time-of-Use Pilot

Forecast 12 Months Ended December 31, 2021

Schedule	Forecast 1/21 - 12/21 Units		Proposed 28 Price	Proposed 28 Dollars	Proposed 29 Price		Proposed 29 Dollars
Schedule No. 29 - Composite							
Pilot General Service							
Transmission & Ancillary Services Charge							
per kWh	2,038,725,738	kWh		$15,076,039	0.739		$15,076,039
System Usage Charge							
Sch 200 related, per kWh	2,038,725,738	kWh		$1,751,746	0.086		$1,751,746
T&A and Sch 201 related, per kWh	2,038,725,738	kWh		$1,568,521	0.077		$1,569,819
Distribution Charge							
Basic Charge	126,732	bills		$5,250,117	$41.00		$5,196,012
Load Size Charge				$8,204,214			
Demand Charge, per kW				$30,479,195			
Reactive Power Charge, per kvar				$406,658			
Distribution Energy Charge, per kWh				$9,080,531			
First 50 kWh per kW Dist. Energy, per kWh	349,570,688	kWh			13.419		$46,908,080
All Addl. kWh Dist. Energy, per kWh	1,689,155,050	kWh			0.078		$1,316,623
Energy Charge - Schedule 200							
All kWh, per kWh	2,038,725,738	kWh		$66,238,853	3.249		$66,238,853
Subtotal	2,038,725,738	kWh		$138,055,874			$138,057,172
Schedule 201							
All kWh, per kWh	2,038,725,738	kWh		$53,534,641	3.044	¢	$62,064,368
Off-Peak Adder, per Off-Peak kWh	1,154,225,576	kWh			-0.739	¢	($8,529,727)
Total	2,038,725,738	kWh		$191,590,515			$191,591,813
Total On-Peak kWh rate, First 50 kWh/kW					**20.614**	**¢**	
Total On-Peak kWh rate, All Addl kWh					**7.274**	**¢**	
Total Off-Peak kWh rate, First 50 kWh/kW					**19.875**	**¢**	
Total Off-Peak kWh rate, All Addl kWh					**6.535**	**¢**	

Schedule 6 TOU definition
Summer (July - September) On-Peak: All Days 1pm to 11pm
Non-Summer (October - June) On-Peak: All Days 5am to 9am and 4pm to 12am (midnight)
Off-Peak: All other hours

Docket No. UE 374
Exhibit PAC/1416
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Schedule 218 Interruptible Service Pilot

February 2020

Pacific Power
State of Oregon
Basis for Proposed Interruptible Demand Credit
Data from Real-Time Energy Imbalance Market
Using Locational Marginal Price at Malin

		12 Mo Ended			
	Unit	**Oct 2017**	**Oct 2018**	**Oct 2019**	**Average**
Event Count	#	51	74	46	57
Total Hours Called	Hours	15.5	26.8	30.3	24.2
Average Event Duration	Hours	0.30	0.36	0.66	0.42
Energy Value Above $200 Trigger	$/MW-year	3,057	9,588	9,927	7,524
Energy Value Above $200 Trigger	$/kW-month				0.63
Proposed Interruptible Demand Credit	$/kW-month				1.00

Interruptible Program Parameters

30 Minute Notice

$200 per MWh during events

Pacific Power
State of Oregon
Example of Potential Bill Savings from Interruptible Program Participation
5 Megawatt, 92% Load Factor Primary Voltage Customer

Bill Before Participation	**Unit**	**Quantity**	**Unit**	**Price**	**Bill Amount**
Demand	On-Peak kW	60,000	$/On-Peak kW	9.75	$585,000
Facilities	kW	60,000	$/kW	1.10	$66,000
Annual Energy	kWh	40,296,000			
On-Peak Energy	kWh	14,506,560	¢/kWh	5.061	$734,177
Off-Peak Energy	kWh	25,789,440	¢/kWh	4.322	$1,114,620
Basic	Months	12	$/month	1,100	$13,200
Total Bill Before Participation			$/year		$2,512,997
Interruptible Demand Credit	On-Peak kW	60,000	$/On-Peak kW	1.00	-$60,000
Interruptible Energy Credit @ 50 Hours per Year	kWh	250,000	¢/kWh	20.00	-$50,000
Administrative Fee	Months	12	$/month	90	$1,080
Net Customer Benefit/(Cost) of Participation			$/year		$108,920
Savings to Bill			%		4.3%
Hours in Year Interrupted			%		0.6%
Potential Annual Hours of Interruption			%		1.1%

Docket No. UE 374
Exhibit PAC/1417
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Schedule 219 Real-Time Day-Ahead Pricing Pilot

February 2020

Pacific Power
State of Oregon
Real-Time Day Ahead Pricing Pilot
5 Megawatt, 92% Load Factor Primary Voltage Customer
Chooses Two Highest Cost Hours Each Day to Avoid
Illustration of Billing

Bill Before Participation	Unit	Quantity	Unit	Price	Bill Amount
Demand	On-Peak kW	60,000	$/On-Peak kW	9.75	$585,000
Facilities	kW	60,000	$/kW	1.10	$66,000
Annual Energy	kWh	40,296,000			
On-Peak Energy	kWh	14,506,560	¢/kWh	5.061	$734,177
Off-Peak Energy	kWh	25,789,440	¢/kWh	4.322	$1,114,620
Basic	Months	12	$/month	1,100	$13,200
Total Bill Before Participation			$/year		$2,512,997

Real-Time Day Ahead Pricing Pilot Billing

Month	Average TAM Price on Schedule 201 ¢/kWh	Average Day Ahead PACW ELAP LMP Price ¢/kWh	Adjustment Factor	Customer's Average Day Ahead PACW ELAP LMP Price ¢/kWh	Customer's Adjusted Average TAM Price on Schedule 201 ¢/kWh	Schedule 201 Energy Charges $	Top 100 Hours of Demand kW	Demand Charges $
January	2.017	4.025	0.50	3.843	1.926	65,664	5,000	48,750
February	2.017	7.640	0.26	7.291	1.925	59,284	5,000	48,750
March	2.017	3.711	0.54	3.410	1.854	63,116	5,000	48,750
April	2.017	2.228	0.91	1.950	1.766	58,268	5,000	48,750
May	2.017	1.839	1.10	1.590	1.743	59,448	5,000	48,750
June	2.017	2.293	0.88	2.066	1.818	59,985	5,000	48,750
July	2.017	5.411	0.37	4.602	1.715	58,495	5,000	48,750
August	2.017	5.064	0.40	4.481	1.785	60,862	5,000	48,750
September	2.017	3.261	0.62	3.068	1.898	62,626	5,000	48,750
October	2.017	4.233	0.48	3.997	1.905	64,946	5,000	48,750
November	2.017	5.109	0.39	4.856	1.917	63,360	5,000	48,750
December	2.017	5.316	0.38	5.087	1.930	65,819	5,000	48,750
Total / Average	2.017	4.177	0.57	3.853	1.848	741,873	60,000	585,000

Bill After Participation	Bill Amount	$/MWh	Savings from Participation $	Savings from Participation %
Bill Before Participation	$2,512,997	62.36		
Administrative Fee	$1,080	0.03		
TAM Energy Charges on Pilot	$741,873	18.41		
Less Standard TAM Energy Charges	-$812,786	(20.17)		
Demand Charges on Pilot	$585,000	14.52		
Less Standard Demand Charges	-$585,000	(14.52)		
Total Bill After Participation	$2,443,164	60.63	-$69,833	-2.8%

Pacific Power
State of Oregon
Real-Time Day Ahead Pricing Pilot
5 Megawatt, 25% Load Factor Primary Voltage Customer
Only Runs When Price is Below 73% of Rolling 15 Day Average Price
Illustration of Billing

Bill Before Participation	Unit	Quantity	Unit	Price	Bill Amount
Demand	On-Peak kW	-	$/On-Peak kW	9.75	$0
Facilities	kW	60,000	$/kW	1.10	$66,000
Annual Energy	kWh	10,950,000			
On-Peak Energy	kWh	-	¢/kWh	5.061	$0
Off-Peak Energy	kWh	10,950,000	¢/kWh	4.322	$473,259
Basic	Months	12	$/month	1,100	$13,200
Total Bill Before Participation			$/year		$552,459

Real-Time Day Ahead Pricing Pilot Billing

Month	Average TAM Price on Schedule 201 ¢/kWh	Average Day Ahead PACW ELAP LMP Price ¢/kWh	Adjustment Factor	Customer's Average Day Ahead PACW ELAP LMP Price ¢/kWh	Customer's Adjusted Average TAM Price on Schedule 201 ¢/kWh	Schedule 201 Energy Charges $	Top 100 Hours of Demand kW	Demand Charges $
January	2.017	4.025	0.50	2.441	1.223	4,219	0	0
February	2.017	7.640	0.26	4.661	1.230	11,259	0	0
March	2.017	3.711	0.54	2.020	1.098	16,692	0	0
April	2.017	2.228	0.91	0.709	0.642	8,183	0	0
May	2.017	1.839	1.10	0.537	0.589	8,358	0	0
June	2.017	2.293	0.88	0.978	0.861	6,886	0	0
July	2.017	5.411	0.37	3.380	1.260	6,992	0	0
August	2.017	5.064	0.40	3.619	1.441	31,423	0	0
September	2.017	3.261	0.62	2.092	1.294	4,723	0	0
October	2.017	4.233	0.48	2.908	1.386	1,039	0	0
November	2.017	5.109	0.39	2.754	1.088	5,764	0	0
December	2.017	5.316	0.38	3.756	1.425	15,035	0	0
Total / Average	2.017	4.177	0.57	2.488	1.128	120,572	0	0

Bill After Participation	Bill Amount	$/MWh	Savings from Participation $	Savings from Participation %
Bill Before Participation	$552,459	50.45		
Administrative Fee	$1,080	0.10		
TAM Energy Charges on Pilot	$120,572	11.01		
Less Standard TAM Energy Charges	-$191,735	(17.51)		
Demand Charges on Pilot	$0	-		
Less Standard Demand Charges	$0	-		
Total Bill After Participation	$482,377	44.05	-$70,082	-12.7%

Docket No. UE 374
Exhibit PAC/1418
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Street and Area Light Price Re-Design

February 2020

Pacific Power
State of Oregon
Present and Proposed Lighting Prices
Lighting Class Cost Analysis
12 Months Ended December 2021

Ownership	Lamp Units*	Annual kWh	Present Description	Present O&M	Present Schedule	Present Monthly Price	Proposed Description	Proposed O&M	Proposed Schedule	Proposed Monthly Price
Company			Outdoor Area Lighting		15		Outdoor Area Lighting		15	
Company	57,790		Mercury Vapor - 7,000 Lumen		15	$9.59	Level 1 (0-5,500 LED Equivalent Lumens)		15	$10.99
Company	12,874		Mercury Vapor - 21,000 Lumen		15	$18.89	Level 2 (5,501-12,000 LED Equivalent Lumens)		15	$14.64
Company	2,281		Mercury Vapor - 55,000 Lumen		15	$40.66	Level 3 (12,001 and Greater LED Equivalent Lumens)		15	$20.75
Company	13,615		High Pressure Sodium Vapor - 5,800 Lumen		15	$9.90	Level 1 (0-5,500 LED Equivalent Lumens)		15	$10.99
Company	4,596		High Pressure Sodium Vapor - 22,000 Lumen		15	$15.46	Level 2 (5,501-12,000 LED Equivalent Lumens)		15	$14.64
Company	1,896		High Pressure Sodium Vapor - 50,000 Lumen		15	$25.90	Level 3 (12,001 and Greater LED Equivalent Lumens)		15	$20.75
Company	1,270		Pole Charge		15	$1.00	Not Applicable			
Company			Mercury Vapor Street Lighting Service		50					
Company	46,052		Wood Pole - 7,000 Horizontal		50	$8.75	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	14,923		Wood Pole - 7,000 Vertical		50	$8.29	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	5,007		Wood Pole - 21,000 Horiztontal		50	$16.79	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	580		Wood Pole - 21,000 Vertical		50	$15.98	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	70		Wood Pole - 55,000 Horizontal		50	$35.72	Level 6 (15,501 and Greater LED Equivalent Lumens)		51	$17.09
Company	1,663		Metal Pole - 7,000 26-ft pole Horizontal		50	$10.85	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	-		Metal Pole - 7,000 26 ft. pole Vertical		50	$10.33	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	790		Metal Pole - 21,000 30 ft. Horizontal		50	$19.26	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	50		Metal Pole - 21,000 30 ft. pole Vertical		50	$18.46	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	-		Metal Pole - 55,000 30 ft. pole Horizontal		50	$38.16	Level 6 (15,501 and Greater LED Equivalent Lumens)		51	$17.09
Company	408		Underground - 7,000 26-ft pole Horizontal		50	$10.85	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	-		Underground - 7,000 26 ft. pole Vertical		50	$10.33	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	617		Underground - 21,000 30 ft. Horizontal		50	$18.75	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	-		Underground - 21,000 30 ft. pole Vertical		50	$17.99	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	-		Underground - 55,000 30 ft. pole Horizontal		50	$37.64	Level 6 (15,501 and Greater LED Equivalent Lumens)		51	$17.09
Company			Street Lighting Service - Company-Owned System		51		Street Lighting Service - Company-Owned System		51	
Company	1,310		LED - 4,000 Lumen		51	$6.52	Level 2 (3,501-5,500 LED Equivalent Lumens)		51	$9.30
Company	1,986		LED - 6,200 Lumen		51	$8.20	Level 3 (5,501-8,000 LED Equivalent Lumens)		51	$10.11
Company	1,139		LED - 13,000 Lumen		51	$14.78	Level 5 (12,001-15,500 LED Equivalent Lumens)		51	$12.98
Company	136		LED - 16,800 Lumen		51	$17.64	Level 6 (15,501 and Greater LED Equivalent Lumens)		51	$17.09
Company	7,032		Cust. Funded Conv. - LED - 4,000 Lumen		51	$6.52	Cust. Funded Conv. - Level 2 (3,501-5,500 LED Equivalent Lumens)		51	$5.69
Company	4,368		Cust. Funded Conv. - LED - 6,200 Lumen		51	$8.20	Cust. Funded Conv. - Level 3 (5,501-8,000 LED Equivalent Lumens)		51	$6.48
Company	360		Cust. Funded Conv. - LED - 13,000 Lumen		51	$14.78	Cust. Funded Conv. - Level 5 (12,001-15,500 LED Equivalent Lumens)		51	$9.13
Company	132		Cust. Funded Conv. - LED - 16,800 Lumen		51	$17.64	Cust. Funded Conv. - Level 6 (15,501 and Greater LED Equivalent Lumens)		51	$12.40
Company	35,690		High Pressure Sodium Vapor - 5,800 Lumen		51	$7.02	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	127,313		High Pressure Sodium Vapor - 9,500 Lumen		51	$8.43	Level 2 (3,501-5,500 LED Equivalent Lumens)		51	$9.30
Company	6,095		High Pressure Sodium Vapor - 16,000 Lumen		51	$10.91	Level 3 (5,501-8,000 LED Equivalent Lumens)		51	$10.11
Company	40,203		High Pressure Sodium Vapor - 22,000 Lumen		51	$13.41	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	8,583		High Pressure Sodium Vapor - 27,500 Lumen		51	$17.63	Level 5 (12,001-15,500 LED Equivalent Lumens)		51	$12.98
Company	9,837		High Pressure Sodium Vapor - 50,000 Lumen		51	$23.77	Level 6 (15,501 and Greater LED Equivalent Lumens)		51	$17.09
Company	405		High Pressure Sodium Vapor - 9,500 Lumen - Decorative Series 1		51	$21.97	Dec Series Level 2 (3,501-5,500 LED Equivalent Lumens)		51	$14.99
Company	278		High Pressure Sodium Vapor - 9,500 Lumen - Decorative Series 2		51	$19.24	Dec Series Level 2 (3,501-5,500 LED Equivalent Lumens)		51	$14.99
Company	76		High Pressure Sodium Vapor - 16,000 Lumen - Decorative Series 1		51	$23.19	Dec Series Level 3 (5,501-8,000 LED Equivalent Lumens)		51	$15.77
Company	59		High Pressure Sodium Vapor - 16,000 Lumen - Decorative Series 2		51	$20.41	Dec Series Level 3 (5,501-8,000 LED Equivalent Lumens)		51	$15.77
Company	777		Metal Halide - 12,000 Lumen		51	$17.68	Level 3 (5,501-8,000 LED Equivalent Lumens)		51	$10.11
Company	982		Metal Halide - 19,500 Lumen		51	$20.96	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company			Street Lighting Service - Company-Owned System		52					
Company	119		High Pressure Sodium Vapor - 5,800 Lumen	$3.39174	52	$5.38	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	36		High Pressure Sodium Vapor - 5,800 Lumen	$5.24174	52	$7.23	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	112		High Pressure Sodium Vapor - 5,800 Lumen	$5.70174	52	$7.69	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	1,575		High Pressure Sodium Vapor - 9,500 Lumen	$7.88376	52	$10.71	Level 2 (3,501-5,500 LED Equivalent Lumens)		51	$9.30
Company	48		High Pressure Sodium Vapor - 22,000 Lumen	$3.59090	52	$9.05	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	24		High Pressure Sodium Vapor - 22,000 Lumen	$7.19090	52	$12.65	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	36		High Pressure Sodium Vapor - 22,000 Lumen	$11.21090	52	$16.67	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	24		High Pressure Sodium Vapor - 22,000 Lumen	$10.38090	52	$15.84	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	-		High Pressure Sodium Vapor - 22,000 Lumen	$10.62090	52	$16.08	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	-		High Pressure Sodium Vapor - 22,000 Lumen	$16.76090	52	$22.22	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	-		High Pressure Sodium Vapor - 22,000 Lumen	$28.68090	52	$34.14	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	24		High Pressure Sodium Vapor - 27,500 Lumen	$7.56710	52	$14.95	Level 5 (12,001-15,500 LED Equivalent Lumens)		51	$12.98
Company	298		High Pressure Sodium Vapor - 50,000 Lumen	$0.00000	52	$11.30	Level 6 (15,501 and Greater LED Equivalent Lumens)		51	$17.09
Company	60		Incandescent - 1,000 Lumen	$0.00000	52	$2.37	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	167		Incandescent - 1,000 Lumen	$1.40498	52	$3.78	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	131		Incandescent - 2,500 Lumen	$0.00000	52	$4.69	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	370		Incandescent - 2,500 Lumen	$1.40442	52	$6.10	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	-		Incandescent - 2,500 Lumen	$1.79442	52	$6.48	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	-		Incandescent - 2,500 Lumen	$2.14442	52	$6.83	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93

Pacific Power
State of Oregon
Present and Proposed Lighting Prices
Lighting Class Cost Analysis
12 Months Ended December 2021

			Present				Proposed			
Ownership	Lamp Units*	Annual kWh	Description	O&M	Schedule	Monthly Price	Description	O&M	Schedule	Monthly Price
Company	-		Incandescent - 2,500 Lumen	$0.00000	52	$4.69	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	12		Incandescent - 4,000 Lumen	$0.70926	52	$8.35	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	-		Incandescent - 4,000 Lumen	$2.18926	52	$9.83	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	-		Incandescent - 4,000 Lumen	$1.41926	52	$9.06	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	155		Incandescent - 4,000 Lumen	$1.45926	52	$9.10	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	349		Incandescent - 4,000 Lumen	$2.03926	52	$9.68	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	-		Incandescent - 6,000 Lumen	$0.96302	52	$11.43	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	-		Incandescent - 6,000 Lumen	$1.50302	52	$11.97	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	60		Incandescent - 6,000 Lumen	$1.54302	52	$12.01	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	-		Incandescent - 6,000 Lumen	$2.72302	52	$13.19	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	12		Mercury Vapor - 7,000 Lumen	$1.05104	52	$5.93	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	36		Mercury Vapor - 7,000 Lumen	$2.47104	52	$7.35	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	322		Mercury Vapor - 7,000 Lumen	$3.84104	52	$8.72	Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	-		Mercury Vapor - 10,700 Lumen	$4.05832	52	$11.00	Level 2 (3,501-5,500 LED Equivalent Lumens)		51	$9.30
Company	12		Mercury Vapor - 21,000 Lumen	$0.84288	52	$11.89	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	-		Mercury Vapor - 21,000 Lumen	$5.21288	52	$16.26	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	24		Mercury Vapor - 21,000 Lumen	$13.23288	52	$24.28	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	36		Other - 22,000 HPSV	$9.08090	52	$14.54	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	-		Other - 16,000 HPS	$6.64000	52	$10.80	Level 3 (5,501-8,000 LED Equivalent Lumens)		51	$10.11
Company	12		Other - 21,000 FLUOR	$6.64000	52	$16.53	Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	501		Other - 16,000 DUPLEX HPS	$11.75000	52	$19.97	Level 3 (5,501-8,000 LED Equivalent Lumens)		51	$10.11
Customer			Street Lighting Service - Customer Owned System		53		Street Lighting Service - Customer Owned System			
Customer		11,928,592	High Pressure Sodium Vapor - Non-Listed Luminaire		53	$0.06242	High Pressure Sodium Vapor - Non-Listed Luminaire		53	$0.061350
Customer	303		High Pressure Sodium Vapor - 9,500 Lumen	$6.83976	53	$9.59	High Pressure Sodium Vapor - 9,500 Lumen	$6.83976	53	$9.54
Customer	97		High Pressure Sodium Vapor - 16,000 Lumen	$0.69056	53	$4.69	High Pressure Sodium Vapor - 16,000 Lumen	$0.69056	53	$4.62
Customer	182		High Pressure Sodium Vapor - 22,000 Lumen	$0.01090	53	$5.32	High Pressure Sodium Vapor - 22,000 Lumen	$0.01090	53	$5.23
Customer	291		High Pressure Sodium Vapor - 27,500 Lumen	$0.08710	53	$7.27	High Pressure Sodium Vapor - 27,500 Lumen	$0.08710	53	$7.14
Customer	145		High Pressure Sodium Vapor - 27,500 Lumen	$2.70710	53	$9.89	High Pressure Sodium Vapor - 27,500 Lumen	$2.70710	53	$7.14
Customer	12		Mercury Vapor - 21,000 Lumen	$0.72088	53	$11.46	Mercury Vapor - 21,000 Lumen	$0.72088	53	$11.27
Customer	-		Mercury Vapor - 21,000 Lumen	$1.46088	53	$12.20	Mercury Vapor - 21,000 Lumen	$1.46088	53	$11.27
Customer	73		Mercury Vapor - 55,000 Lumen	$0.09048	53	$25.87	Mercury Vapor - 55,000 Lumen	$0.09048	53	$25.43
Customer			Recreational Field Lighting		54		Recreational Field Lighting		54	
Customer	816		Basic Charge - Single Phase		54	$6.00	Basic Charge - Single Phase		54	$6.00
Customer	445		Basic Charge - Three Phase		54	$9.00	Basic Charge - Three Phase		54	$9.00
Customer		1,457,127	Energy Charge		54	$0.07679	Energy Charge		54	$0.075440
			Unique Price Count			90				

*Proposal includes treating existing duplex lamps as two different level 3 street lights

Pacific Power
State of Oregon
Consolidated Proposed Lighting Prices
Lighting Class Cost Analysis
12 Months Ended December 2021

Ownership	Lamp Units*	Annual kWh	Proposed Description	O&M	Schedule	Monthly Price
Company			Outdoor Area Lighting		15	
Company	71,405		Level 1 (0-5,500 LED Equivalent Lumens)		15	$10.99
Company	17,470		Level 2 (5,501-12,000 LED Equivalent Lumens)		15	$14.64
Company	4,177		Level 3 (12,001 and Greater LED Equivalent Lumens)		15	$20.75
Company			Street Lighting		51	
Company	100,677		Level 1 (0-3,500 LED Equivalent Lumens)		51	$8.93
Company	130,198		Level 2 (3,501-5,500 LED Equivalent Lumens)		51	$9.30
Company	9,860		Level 3 (5,501-8,000 LED Equivalent Lumens)		51	$10.11
Company	48,445		Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$11.81
Company	9,746		Level 5 (12,001-15,500 LED Equivalent Lumens)		51	$12.98
Company	10,341		Level 6 (15,501 and Greater LED Equivalent Lumens)		51	$17.09
Company	-		Cust. Funded Conv. - Level 1 (0-3,500 LED Equivalent Lumens)		51	$5.55
Company	7,032		Cust. Funded Conv. - Level 2 (3,501-5,500 LED Equivalent Lumens)		51	$5.69
Company	4,368		Cust. Funded Conv. - Level 3 (5,501-8,000 LED Equivalent Lumens)		51	$6.48
Company	-		Cust. Funded Conv. - Level 4 (8,001-12,000 LED Equivalent Lumens)		51	$8.15
Company	360		Cust. Funded Conv. - Level 5 (12,001-15,500 LED Equivalent Lumens)		51	$9.13
Company	132		Cust. Funded Conv. - Level 6 (15,501 and Greater LED Equivalent Lumens)		51	$12.40
Company	683		Dec Series Level 2 (3,501-5,500 LED Equivalent Lumens)		51	$14.99
Company	135		Dec Series Level 3 (5,501-8,000 LED Equivalent Lumens)		51	$15.77
Customer			Street Lighting Service - Customer Owned System		53	
Customer		11,928,592	High Pressure Sodium Vapor - Non-Listed Luminaire		53	$0.06135
Customer	303		High Pressure Sodium Vapor - 9,500 Lumen	$6.83976	53	$9.54
Customer	97		High Pressure Sodium Vapor - 16,000 Lumen	$0.69056	53	$4.62
Customer	182		High Pressure Sodium Vapor - 22,000 Lumen	$0.01090	53	$5.23
Customer	291		High Pressure Sodium Vapor - 27,500 Lumen	$0.08710	53	$7.14
Customer	145		High Pressure Sodium Vapor - 27,500 Lumen	$2.70710	53	$9.76
Customer	12		Mercury Vapor - 21,000 Lumen	$0.72088	53	$11.27
Customer	-		Mercury Vapor - 21,000 Lumen	$1.46088	53	$12.01
Customer	73		Mercury Vapor - 55,000 Lumen	$0.09048	53	$25.43
Customer			Recreational Field Lighting		54	
Customer	816		Basic Charge - Single Phase		54	$6.00
Customer	445		Basic Charge - Three Phase		54	$9.00
Customer		1,457,127	Energy Charge		54	$0.07544
			Unique Price Count			29

*Proposal includes treating existing duplex lamps as two different level 3 street lights