BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 374

In the Matter of PACIFICORP REQUEST FOR A GENERAL RATE REVISION, Request for a General Rate Revision	STAFF'S CROSS-EXAMINATION EXHIBITS

Pursuant to Administrative Law Judge Lackey's August 27, 2020 Ruling, Staff submits the following cross-examination exhibits in Docket UE 374, not previously filed in this case:

Cross-Examination Exhibit	**Description**
Staff/3200	2020 Protocol
Staff/3300	PacifiCorp's Response to Staff DRs 92 (attachment), 126 (attachment), 272, 769, 770, 771 (CONF), 772 (CONF), 773 (with attachment), 774, 775 and 776. Attachments to PacifiCorp's responses to 123, 178, 242 and 696.[1]
Staff/3400	PacifiCorp's Response to Staff DRs 311, 312 (1st Supplemental response), 313 (1st Supplemental Response), 725, 726, 727 (CONF), 730, 794, 796, 797, 799, 800, 801, 803, 804, 807, 809, 811, 819 and 824; PacifiCorp's Response to AWEC 057 (attachments only)[2]
Staff/3500	PacifiCorp's Response to Staff DRs 530, 471, 499 (CONF), 826, 827, 828, 830 (CONF) and 831

[1] PacifiCorp's responses to these Data Requests are already included in the record in either Staff/402 or Staff/2501.

[2] PacifiCorp's response to AWEC 057 was previously included in Staff/1704.

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Staff/3600	PacifiCorp's Response to Staff DR 793
Staff/3700	PacifiCorp's Response to Staff DRs 515, 761, 762, and 792 (with attachment)

DATED this 2nd day of September, 2020.

Respectfully submitted,

ELLEN F. ROSENBLUM
Attorney General

/s/ Sommer Moser

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PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF CROSS-EXHIBIT 3200

September 2, 2020

Docket No. UM 1050
Exhibit PAC/101
Witness: Etta P. Lockey

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Etta P. Lockey

2020 Protocol

December 2019

EXECUTION VERSION

2020 PacifiCorp Inter-Jurisdictional Allocation Protocol

EXECUTION VERSION

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EXECUTION VERSION

1. Introduction

This 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol Agreement (the "2020 Protocol" or this "Agreement") reflects the agreement among PacifiCorp (or the "Company"), certain Commission[1] staff members, State regulatory agencies, customers, consumer advocates, conservation organizations, and other interested parties from California, Idaho, Oregon, Utah, Washington, and Wyoming (collectively referred to as the "States" or individually as a "State") who have executed this Agreement (collectively referred to as the "Parties" or individually as a "Party") on an interim allocation and assignment method and a process for determining a long-term replacement of existing inter-jurisdictional allocation and assignment methodologies.[2] The 2020 Protocol is intended to: (1) supersede the 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol (the "2017 Protocol") for California, Idaho, Oregon, Utah, and Wyoming; and (2) modify the West Control Area Inter-jurisdictional Allocation Methodology ("WCA") for Washington. However, as part of the 2020 Protocol, the 2017 Protocol and the WCA allocation methodologies will continue to be used, with modifications explained herein, during an Interim Period, as defined below. Subject to the provisions set forth below, and with the acknowledgment that only the appropriate state body charged with issuing orders to establish rates can approve its use, the Parties agree that the 2020 Protocol can be used to set just and reasonable rates and agree to support its use in rate filings in California, Idaho, Oregon, Utah, Washington, and Wyoming during the Interim Period. The 2020 Protocol includes:

- The allocation and assignment policies, procedures, and methods to be used during the Interim Period (i.e., January 1, 2020 through December 31, 2023, as specified

[1] Capitalized terms in the 2020 Protocol are defined herein, in Appendix A, or in Appendix C.
[2] For purposes of this Agreement, use of the terms assign, assignment, and assigned generally refer to the generation, capacity, benefits, and risks associated with certain assets and use of the terms allocate, allocated, allocation generally refer to the treatment of costs associated with certain assets.

in Section 2). The 2020 Protocol describes the way all components of PacifiCorp's regulated service, including costs, revenues, and benefits associated with generation, transmission, distribution, and wholesale transactions, should be allocated and assigned among the six States during the Interim Period. During the Interim Period, these inter-jurisdictional allocation policies, procedures, or methods, if applied by each State as stated herein for rate proceedings filed during the Interim Period, can provide PacifiCorp a reasonable opportunity to recover its prudently incurred cost of service.

- An agreement on certain issues that are intended to be implemented during the Interim Period and, assuming final resolution of all outstanding issues, incorporated into a Post-Interim Period Method agreement ("Implemented Issues").
- A conditional agreement on certain issues intended to be implemented following the Interim Period, subject to final resolution of all outstanding issues ("Resolved Issues").
- A process and timeframe to address and attempt to resolve all outstanding issues that the Parties intend to resolve after this 2020 Protocol has been filed with the Commissions and during the Interim Period ("Framework"), including the implementation or resolution of issues associated with a Nodal Pricing Model, Resource planning and new Resource Assignment, Limited Realignment, Special Contracts, post-Interim Period capital additions on coal-fueled Interim Period Resources and other items ("Framework Issues"). The future resolution of Framework Issues, combined with the Implemented Issues and the Resolved Issues, would result in a new allocation methodology for PacifiCorp's six States ("Post-

Interim Period Method").

The proposed allocation of a particular expense or investment to a State under the 2020 Protocol is not intended to and will not prejudge the prudence of that cost or the extent to which any particular cost may be reflected in rates. Nothing in the 2020 Protocol is intended to abrogate any Commission's right or obligation to: (1) determine fair, just, and reasonable rates based upon applicable laws and the record established in rate proceedings conducted by that Commission; (2) consider the effect of changes in laws, regulations, or circumstances on inter-jurisdictional allocation policies and procedures when determining fair, just, and reasonable rates; or (3) establish different allocation policies and procedures for purposes of allocating costs and revenues within that State to different customers or customer classes.

Parties support the 2020 Protocol, but their support will not, in any manner, affect or negate their right to address changed or unforeseen circumstances, including changes in laws or regulations. A Party's support of the 2020 Protocol will not bind or be used against that Party if a Party concludes that the 2020 Protocol no longer produces results that are just, reasonable, or in the public interest, or does not provide the Company with a reasonable opportunity to recover its prudently incurred cost of service; provided, however, that in raising an objection to the 2020 Protocol the Parties agree to first raise any such objection by following the provisions of Section 8.4.

Support of the 2020 Protocol does not constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory, or principle of regulation, cost recovery, cost of service, or rate design. No Party will be deemed to have agreed that any particular method, theory, or principle of regulation, Resource acquisition or Reassignment, cost recovery, cost of service, or rate design employed in or implied by the 2020 Protocol is appropriate for resolving any issues other than the inter-jurisdictional allocation of PacifiCorp's cost of service. The Parties have made no effort to address or consider intra-state cost allocation issues and agree that using the 2020 Protocol for inter-jurisdictional cost allocation purposes does not suggest or require similar treatment be applied to intra-state cost allocations for class cost-of-service purposes for any State. Parties may propose such methods of intra-state class cost-of-service allocations as they deem appropriate.

The 2020 Protocol includes the following appendices described briefly below:

- Terms that are capitalized in the 2020 Protocol are defined herein, in Appendix A, or in Appendix C.
- Appendix B includes tables identifying the allocation factor to be applied to each component of PacifiCorp's revenue requirement calculation.
- Appendix C includes the definition and algebraic derivation of each allocation factor, along with the FERC accounts to which the allocation factor will be applied.
- Appendix D is a Memorandum of Understanding among the Parties supporting the Company's acquisition and implementation of a Nodal Pricing Model.
- Appendix E includes a table reflecting Commission-approved depreciable lives in effect October 1, 2019, and the Company's proposed depreciable lives for coal-fueled Interim Period Resources in pending depreciation dockets as filed in September 2018.
- Appendix F is the Washington Inter-Jurisdictional Allocation Methodology Memorandum of Understanding between the Company and the Washington Parties, which modifies the WCA.

- Appendix G includes a description and numeric example of how Special Contracts and related issues will be treated during the Interim Period.

2. Timeframes and Effective Periods

2.1. Effective Period of the 2020 Protocol

For the Interim Period, January 1, 2020 through December 31, 2023, subject to Section 2.2.4, the Parties agree to support before their respective Commissions the use of the 2020 Protocol in PacifiCorp regulatory proceedings or filings, subject to exceptions for deferred amounts including, but not limited to, Net Power Costs as set forth in this Agreement. The 2020 Protocol includes an agreed-upon approach for cost allocations to each State that will be used by PacifiCorp in proceedings or filings commenced during the Interim Period, except as provided in Section 2.2.5.

2.2. Post-Interim Period

2.2.1. Commission Approvals for Post-Interim Period Method Obtained Prior to December 31, 2023

If each State's Commission approves a Post-Interim Period Method agreement on or before December 31, 2023, or in the first general rate case after the Post-Interim Period Method agreement is reached,[3] the Interim Period will terminate on December 31, 2023, and the Post-Interim Period Method will take effect, subject to Section 2.2.2.

2.2.2. Commission Approval Not Granted

If any Commission denies PacifiCorp's request for approval of the Post-Interim Period Method agreement, PacifiCorp will propose an alternative allocation method for the Post-Interim Period for consideration by all the Commissions. Parties are free to take any position regarding

[3] The Parties understand the California and Washington Commissions will likely consider the Post-Interim Period Method in the first general rate case filed in either State after an agreement has been reached on the Post-Interim Period Method, and approval may occur after December 31, 2023.

PacifiCorp's proposal, including proposing alternative allocation methodologies, filing a complaint, or requesting an investigation of PacifiCorp's proposal.

2.2.3. Post-Interim Period Method Agreement Not Reached

If the Company determines that it is unlikely that a Post-Interim Period Method agreement will be reached before the end of the Interim Period, then the Company will propose an allocation method for the Post-Interim Period for consideration by the Commissions. Parties are free to take any position regarding PacifiCorp's proposal, including proposing alternative allocation methodologies, or initiating a complaint or investigation of PacifiCorp's proposal.

2.2.4. Early Commission Approvals of Post-Interim Period Method

If a Post-Interim Period Method agreement is reached on or before December 31, 2022, any Post-Interim Period Method agreement will address whether and the degree to which the Company will use the Post-Interim Period Method in regulatory proceedings or filings commenced after December 31, 2022.

2.2.5. Regulatory Filings to Implement Post-Interim Period Method

Any Post-Interim Period Method agreement will address whether and the degree to which the Company may use the Post-Interim Period Method in regulatory proceedings or filings commenced during the Interim Period while Commission approvals of the Post-Interim Period Method agreement are pending but to be effective after the end of the Interim Period.

3. Interim Period Allocation Method

The 2017 Protocol expires December 31, 2019.[4] The Parties representing interests in the States of California, Idaho, Oregon, Utah, and Wyoming (collectively referred to as the "Five State Parties" and the "Five States") agree that the methodology outlined in the 2017 Protocol being

[4] As proposed in PacifiCorp's 2019 California general rate case filing, the 2017 Protocol does not expire in California on December 31, 2019.

used by the Company in 2019 should continue, as outlined and modified in Section 3, during the Interim Period while the Parties continue to negotiate the Framework Issues necessary to develop the Post-Interim Period Method. The Washington Parties agree that the methodology outlined in the WCA being used in 2019 should, subject to the terms included in Appendix F, continue during the Interim Period while the Parties continue to negotiate the Framework Issues necessary to develop the Post-Interim Period Method.

For the Five States, the terms of the 2017 Protocol that will be used during the Interim Period under the 2020 Protocol are provided in Section 3.1. The 2017 Protocol terms that are being modified by this Agreement are provided in Section 3.2.

3.1. Continuing Terms of the 2017 Protocol for the Five States Interim Period Allocation Methodology[5]

Items included in the Company's results of operations will be allocated on the factors set forth below. The FERC account and allocation factor combinations are included in Appendix B. The algebraic derivation and factor definitions are included in Appendix C.

3.1.1. Classification of Interim Period Resources

All Fixed Costs of Interim Period Resources will be classified as 75 percent Demand-Related and 25 percent Energy-Related. All Non-Firm Purchases and Sales will be classified as 100 percent Energy-Related.

3.1.2. Allocation of Interim Period Resource Costs and Wholesale Revenues

Interim Period Resources will be allocated to one of two categories for inter-jurisdictional allocation purposes: State Resources or System Resources. A complete description of allocation factors to be used is set forth in Appendix B.

[5] Terminology in Section 3.1 has been modified from the language in the 2017 Protocol to maintain consistency in the use of terms within the 2020 Protocol.

There are three types of State Resources. The remaining types of Interim Period Resources are System Resources, which constitute the substantial majority of PacifiCorp's Resources. Benefits and costs associated with each category and type of Interim Period Resource will be assigned or allocated to States on the following basis.

3.1.2.1. Interim Period State Resources

Benefits and costs associated with the three types of State Resources will be assigned or allocated as follows:

- Demand-Side Management ("DSM") Programs: Costs associated with DSM Programs, including Class 1 DSM Programs, will be allocated on a situs basis to the State in which the investment is made. Benefits from these programs, in the form of reduced consumption and contribution to Coincident Peak, will be reflected in the Load-Based Dynamic Allocation Factors.
- Portfolio Standards: The portion of costs associated with Interim Period Resources acquired to comply with a State's Portfolio Standard adopted, either through legislative enactment or by a State's Commission, that exceed the costs PacifiCorp would have otherwise incurred, will be allocated on a situs basis to the Jurisdiction adopting the Portfolio Standard.
- State-Specific Initiatives: Costs and benefits associated with Interim Period Resources acquired in accordance with a State-specific initiative will be allocated and assigned on a situs basis to the State adopting the initiative. State-specific initiatives include, but are not limited to, the costs and benefits of incentive programs, net-metering tariffs, feed-in tariffs, capacity standard programs, solar

subscription programs, electric vehicle programs, and the acquisition of renewable energy certificates.

3.1.2.2. Interim Period System Resources

All Interim Period Resources that are not State Resources are System Resources and will be allocated as follows:

- Generally, all Fixed Costs associated with System Resources and all costs incurred under Wholesale Contracts will be allocated based upon the System Generation ("SG") Factor.
- Generally, all Variable Costs associated with System Resources will be allocated based upon the System Energy ("SE") Factor.
- Revenues received by PacifiCorp under Wholesale Contracts will be allocated based upon the SG Factor.

3.1.3. Re-functionalization and Allocation of Transmission Costs and Revenues

Before filing any request to approve a reclassification of facilities as transmission or distribution with FERC, PacifiCorp will submit filings seeking review and authorization of any such reclassification with the Commissions. The cost responsibility for any assets reclassified under FERC policy will be assigned or allocated consistent with other assets in the relevant function.

Costs associated with transmission assets, and firm wheeling expenses and revenues, will be classified as 75 percent Demand-Related, 25 percent Energy-Related, and allocated based upon the SG Factor. Non-firm wheeling expenses and revenues will be allocated based upon the SE Factor. In the event that PacifiCorp joins a regional independent system operator, the allocation of transmission costs and revenues may be reevaluated and revised as provided for in Section 8.4.

3.1.4. Allocation of Distribution Costs

All distribution-related expenses and investment that can be directly allocated will be directly allocated to the State where they are located. Those costs that cannot be directly allocated will be allocated consistent with the factors set forth in Appendix B.

3.1.5. Allocation of Administrative and General Costs

Administrative and General Costs, General Plant costs, and Intangible Plant costs will be allocated consistent with the factors set forth in Appendix B.

3.1.6. Allocation of Special Contracts

Revenues associated with Special Contracts will be included in State revenues, and loads of Special Contract customers will be included in Load-Based Dynamic Allocation Factors as appropriate (see Appendix G). Special Contracts may or may not include Customer Ancillary Service Contract attributes. Load curtailments and buy-through arrangements will be handled as appropriate (see Appendix G).

3.1.7 Miscellaneous Costs and Taxes

Miscellaneous costs described below will be allocated as follows:

- Generation-related dispatch costs and associated plant will be allocated on the SG Factor.
- Miscellaneous regulatory assets and liabilities, and miscellaneous deferred debits will be allocated with the appropriate allocation factor depending on the related assets or underlying costs.

Taxes and fees will be allocated as follows:

- Income taxes will be calculated using the federal tax rate and PacifiCorp's combined State effective tax rate. State-specific Schedule M and deferred income tax amounts will be allocated using the Company's tax software system. Consistent with prior system allocation methods, the Washington Public Utility Tax is allocated using the SO Factor in lieu of a Washington income tax.

- Franchise taxes, revenue related taxes, Commission assessments and fees, and usage related taxes are situs or a pass through.
- Property taxes are system allocated based on gross plant and allocated on a Gross Plant System ("GPS") Factor.
- Generation and fuel-related taxes will be allocated using the SG Factor.
- Other taxes such as payroll taxes are embedded in expenses or capital costs.

Balances associated with the Trojan Decommissioning will be allocated using the Trojan Decommissioning ("TROJD") Factor. This will not impact State-specific treatment of this item.

3.1.8. State Programs Regarding Access to Alternative Electricity Suppliers

3.1.8.1. Treatment of Oregon Direct Access Programs

This Section describes treatment of loads lost to Oregon Direct Access Programs during the term of the 2020 Protocol.

3.1.8.1.1. Customers Electing PacifiCorp's One- and Three-Year Oregon Direct Access Programs

Customer loads electing to be served on PacifiCorp's one- and three-year Oregon Direct Access Programs will be included in the Load-Based Dynamic Allocation Factors for all Interim Period Resources, and the transition cost payments from these customers will be situs assigned and allocated to Oregon.

3.1.8.1.2. Customers Electing PacifiCorp's Five Year Opt-Out Program Under the Oregon Direct Access Program

The treatment will be consistent with Order No. 15-060, as clarified through Order No. 15-067, of the Oregon Public Utility Commission in Docket UE 267, and Oregon Schedule 296, which allow Oregon Direct Access Consumers to permanently opt-out of cost-of-service rates after payment of ten years of transition costs in Oregon. If an Oregon Direct Access Consumer is paying transition costs during the Interim Period, the Oregon Direct Access Consumer's load(s) will be included in Load-Based Dynamic Allocation Factors, and the transition cost payments from these consumers will be situs-assigned to Oregon. If any Oregon Direct Access Consumer reaches the end of the 10-year period covered by the transition cost payments during the Interim Period, the load(s) for that Oregon Direct Access Consumer will be excluded from Load-Based Dynamic Allocation Factors. Thereafter, if an Oregon Direct Access Consumer elects to return to Oregon cost-of-service rates by providing four-years notice under Schedule 296, its load will be treated as new load and incorporated in PacifiCorp's Resource planning process.

3.1.8.1.3. New Laws or Regulations

To the extent Oregon adopts new laws or regulations regarding Oregon Direct Access Programs, Oregon's treatment of loads lost to Oregon Direct Access Programs may be re-determined in a manner consistent with the new laws and regulations. In the event Oregon adopts such new laws or regulations, the Company will inform the Commissions and the Parties of the same.

3.1.8.2. Utah Eligible Customer Program

If, pursuant to Utah Code Annotated Section 54-3-32, an eligible customer in Utah transfers service to a non-utility energy supplier, the Public Service Commission of Utah will make determinations under Utah law as contemplated therein. The Company will inform the Commissions and the Parties of the Public Service Commission of Utah's determinations.

3.1.8.3. Other State Actions

In the event any State adopts laws or regulations governing customer access to alternative electricity suppliers, the Company will inform the Commissions and the Parties of the same.

3.1.9. Loss or Increase in Load

Any loss or increase in retail load occurring as a result of condemnation or municipalization, sale or acquisition of new service territory that involves less than five percent of system load, realignment of service territories, changes in economic conditions, or gain or loss of large customers will be reflected in changes in the Load-Based Dynamic Allocation Factors. The allocation or assignment of costs and benefits arising from merger, sale, or acquisition transaction proposed by the Company involving more than five percent of system load will be considered on a case-by-case basis in the course of Commission approval proceedings.

3.1.10. Commission Regulation of Interim Period Resources

PacifiCorp will plan and acquire new Interim Period Resources on a system-wide risk-adjusted, least-cost basis. Prudently incurred investments in Interim Period Resources will be reflected in rates consistent with the laws and regulations in each State, as approved by individual Commissions.

3.2. Modifications to the 2017 Protocol During the Interim Period

3.2.1. Net Power Costs Filings

For Net Power Costs ("NPC") filings, Parties agree to support use of the allocation methodology in place when the NPC were or will be incurred, to align the timing of the actual costs incurred with the applicable allocation method for cost recovery for that period. The table below summarizes the transition from the 2017 Protocol to the 2020 Protocol for NPC filings. If a Post-Interim Period Method agreement is reached between the Parties, a similar table will be included to summarize the transition for NPC filings from the 2020 Protocol to the subsequent agreement.

Allocation Methodology Used for NPC Filings					
Filing	**2017 Protocol**		**2020 Protocol**		**Notes**
California ECAC (Balancing Rate)	2021 ECAC for the CY2020 Deferral Period		2022 ECAC for the CY2021 Deferral Period		1
California ECAC (Offset Rate)	2020 ECAC for the CY2020 Forecast Period		2021 ECAC for the CY2021 Forecast Period		1
Idaho ECAM	2020 ECAM for the CY2019 Deferral Period		2021 ECAM for the CY2020 Deferral Period		
Oregon TAM	2020 TAM for the CY2019 Forecast Period		2021 TAM for the CY2020 Forecast Period		
Oregon PCAM	2020 PCAM for the CY2019 Deferral Period		2021 PCAM for the CY2020 Deferral Period		
Utah EBA	2020 EBA for the CY2019 Deferral Period		2021 EBA for the CY2020 Deferral Period		
Washington PCAM	2019 PCAM for the CY2019 Deferral Period		2020 PCAM for the CY2020 Deferral Period		2
Wyoming ECAM	2020 ECAM for the CY2019 Deferral Period		2021 ECAM for the CY2020 Deferral Period		
Net Power Costs included in General Rate Cases (GRC) - All States			GRC with rate effective date on or after January 1, 2020		3
Notes:					
1. The 2020 Protocol will not be implemented in California until approved by the Commission in a general rate case. The dates included in the table are subject to change based on the California general rate case schedule, the next general rate case is currently scheduled to use a 2022 test period.					
2. Washington will use the modified WCA allocation methodology per Appendix F of the 2020 Protocol.					
3. This also applies to any other NPC filing that resets base NPC rates.					

3.3.2. Embedded Cost Differential ("ECD") and Equalization Adjustment

3.3.2.1. ECD

The Fixed ECD will continue for Idaho through the end of the Interim Period. The Dynamic ECD for Oregon will continue through the end of the Interim Period, capped at $11,000,000. No ECD adjustment exists for Utah or California.

The Wyoming ECD will terminate December 31, 2020. Beginning January 1, 2021, for purposes of the Wyoming energy cost adjustment mechanism ("ECAM"), actual ECD will be zero and the true-up of the Wyoming ECD will not be subject to sharing bands in the Wyoming ECAM. This treatment will continue until the ECD is removed from base rates.

3.3.2.2. Equalization Adjustment

The Equalization Adjustment addressed in Section XIV of the 2017 Protocol will terminate on December 31, 2019, and no additional Equalization Adjustment amounts will be deferred after that date. The method PacifiCorp will use to collect deferred Equalization Adjustment balances and any related carrying charges has been or will be addressed in appropriate State regulatory proceedings.

3.3.3. Costs and Benefits of Qualifying Facilities

Costs and benefits of Qualifying Facilities will be treated consistent with the provisions specified in Section 4.4.

3.3.4. Allocation of Gain or Loss from Sale of Assets

The allocation of any gain or loss from the Company's sale of assets will be treated consistent with the provisions specified in Section 7.

3.3.5. Interpretation and Governance

This Agreement will be interpreted and PacifiCorp's Multi-State Process ("MSP") will be governed by the provisions specified in Section 8.

4. Implemented Issues

The Parties agree that the following items, described later in this Section 4, will be implemented and effective during the Interim Period:

- The process and timing for States' decisions to exit coal-fueled Interim Period Resources;
- The process for potential Reassignment of coal-fueled Interim Period Resources among States without Exit Orders;
- The process for the allocation of Decommissioning Costs; and
- The allocation and assignment of Qualifying Facility Power Purchase Agreements

("QF PPAs").

These issues are more thoroughly explained below.

4.1. States' Decisions to Exit Coal-Fueled Interim Period Resources

PacifiCorp will continue to conduct operational and economic analyses in accordance with applicable regulatory requirements and good utility practice to maintain reliable service on a risk-adjusted, least-cost basis for its customers. PacifiCorp anticipates continuing to conduct integrated resource planning, at least biennially. PacifiCorp also anticipates continuing to undertake depreciation studies on a five-year cycle. If these analyses affect the depreciable lives or operational lives of Interim Period Resources in the future, Parties may address such effects through appropriate regulatory proceedings before the Commissions. Nothing in this Agreement affects PacifiCorp’s rights and obligations to make prudent decisions regarding operation of its assets and system in accordance with applicable law. The Parties further agree that PacifiCorp’s coal-fueled Interim Period Resource Closure dates may be informed by new information that becomes available as a result of other regulatory filings or actions, including integrated resource plans or State and federal energy policies. Nothing in this Agreement affects or limits any Party’s ability to raise any prudence issues with regards to PacifiCorp’s decisions regarding Closure of an Interim Period Resource.

Subject to the possible effects of Limited Realignment, the Parties agree to the following procedures for the Company's coal-fueled Interim Period Resources.

4.1.1. Allocation of Costs at Closure

Upon Closure of a coal-fueled Interim Period Resource, each State that is receiving benefits and is allocated costs associated with the coal-fueled Interim Period Resource at the time of Closure shall continue to be allocated its share of the remaining costs of the coal-fueled Interim

Period Resource in accordance with this 2020 Protocol, which may include the remaining net book value and Commission-approved Decommissioning Costs. The existence of an Exit Order does not change this allocation, and all States assigned benefits and allocated costs from the coal-fueled Interim Period Resource at the time of Closure will be allocated actual costs. Therefore, if every State is being assigned benefits and allocated costs from a coal-fueled Interim Period Resource at the time of Closure, every State will be allocated, in accordance with the method set forth in this Agreement, all the actual costs associated with that coal-fueled Interim Period Resource and its Closure. This can occur, for example, if every State (excepting Washington as discussed in Section 4.1.4) issues an Exit Order with the same Exit Date for a particular coal-fueled Interim Period Resource. This can also occur, for example, if PacifiCorp pursues Closure of a coal-fueled Interim Period Resource prior to a State Exit Date. No Party, by virtue of this Agreement, waives its right to investigate and analyze whether the Company's decision to continue operation or continue an ownership interest is prudent, regardless of the anticipated Closure dates in the tables in Section 4.1.3.

4.1.2 Exit Orders

The Parties, representing diverse and varied interests, have worked in good faith to create a process that allows for States to pursue differing resource portfolios in the future, including decisions to transition out of coal-fueled Interim Period Resources while mitigating resulting effects to the Company and other States. A Commission may issue an Exit Order specifying an Exit Date in a proceeding for approval of this Agreement, a depreciation docket, a rate case, or any other appropriate proceeding.[6] A Commission Order or other determination that a coal-fueled Interim Period Resource will reach the end of its depreciable life without a specific determination

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[6] An Exit Order is not required from a Commission if a coal-fueled Interim Period Resource is not included in PacifiCorp's rates in that State.

that the State will exit the Interim Period Resource shall not constitute an Exit Order. Provided PacifiCorp secures all applicable approvals, a Company decision to close a coal-fueled Interim Period Resource earlier than previously anticipated does not require the issuance of an Exit Order. An Exit Order does not, by itself, result in Reassignment of shares of a coal-fueled Interim Period Resource to other States or affect an Exiting State's responsibility for its share of the then-remaining net book value of the Interim Period Resource that is being exited.

To provide the Company and States without Exit Orders time to consider the options and address the potential Reassignment of the coal-fueled Interim Period Resource, as set forth in Section 4.2, under this Agreement an Exit Order should provide at least four-years of notice[7] from the date of the Exit Order to the Exit Date. After an Exit Date, the Exiting State will no longer be allocated any new costs[8] and will no longer be assigned any benefits associated with that coal-fueled Interim Period Resource, and no other State will be allocated the Exiting State's share of costs nor receive the Exiting State's assigned benefits associated with that coal-fueled Interim Period Resource, unless the costs and benefits are accepted through a Commission Order on Reassignment. Until the Exit Date, an Exiting State shall continue to be assigned the benefits of that coal-fueled Interim Period Resource and shall be allocated costs associated with that coal-fueled Interim Period Resource in accordance with this 2020 Protocol or as determined through the Framework process, which may include costs associated with any remaining net book value, prudently incurred capital additions, prudently incurred Operations and Maintenance ("O&M") expense, and prudently incurred or reasonably estimated Decommissioning Costs.

[7] Subject to the provisions in Sections 4.1.3 and 4.1.4.

[8] New costs are costs incurred after the Exit Date to maintain or operate the coal-fueled Interim Period Resource beyond that date. Any costs associated with the operation of a coal-fueled Interim Period Resource and incurred prior to the Exit Date that are allocated to the Exiting State as determined through the 2020 Protocol and that have not yet been collected from customers in that State are still that State's responsibility.

An Exit Order establishes the Exit Date that PacifiCorp will use to propose the allocation of Decommissioning Costs, allocation of capital additions costs, and any other associated costs related to the exit from a coal-fueled Interim Period Resource as outlined in the 2020 Protocol. PacifiCorp will timely propose to Parties from an Exiting State a method to address the treatment of these costs for ratemaking, such that costs and benefits remain matched in customer rates.

Following receipt of an Exit Order, the Company will file in accordance with Section 4.2 to allow States without Exit Orders the opportunity to evaluate the potential Reassignment of the coal-fueled Interim Period Resource. For regulatory efficiency, Section 4.1.3 establishes timeframes for addressing Exit Orders from coal-fueled Interim Period Resources by Oregon and the potential Reassignment of those resources to other States.

4.1.3 Oregon Exit Dates

The Oregon Parties and the Company agree to recommend that the dates shown in the tables in this Section 4.1.3 be used in Oregon for service and depreciable lives, and for establishing Oregon's Exit Dates for all coal-fueled Interim Period Resources.

4.1.3.1 Coal-Fueled Interim Period Resources Not Operated by PacifiCorp Subject to Common Closure Dates, Oregon Exit 2023-2027

PacifiCorp anticipates that Cholla Unit 4, Craig Unit 1, Craig Unit 2, Colstrip Unit 3, and Colstrip Unit 4 will have common Closure dates for all States. If PacifiCorp effectuates Closure at Cholla Unit 4, Craig Unit 1, Craig Unit 2, Colstrip Unit 3, or Colstrip Unit 4 on or before the applicable dates identified in the table below, each State will be allocated its share of the costs and benefits of that coal-fueled Interim Period Resource with no transfer of cost responsibility or decommissioning liability among States, in accordance with Section 4.1.1.

PacifiCorp and the Oregon Parties agree to recommend to the Oregon Commission that the dates shown in the table below be used for establishing Oregon's Exit Dates and Oregon depreciable lives for Cholla Unit 4, Craig Unit 1, Craig Unit 2, Colstrip Unit 3, and Colstrip Unit 4.

Coal-Fueled Interim Period Resource Name	Anticipated Closure Date
Cholla Unit 4	January 1, 2023
Craig Unit 1	December 31, 2025
Craig Unit 2	December 31, 2026
Colstrip Unit 3	December 31, 2027
Colstrip Unit 4	December 31, 2027

PacifiCorp and the Oregon Parties agree that PacifiCorp will make best efforts to effectuate Closure of the units identified above by the anticipated Closure dates, but the Company may need additional time for Closure of Craig Units 1 and 2 and Colstrip Units 3 and 4 due to its joint-owner agreements, and Cholla Unit 4 due to other contractual requirements.

If PacifiCorp has received an Exit Order from Oregon for Craig Unit 1, Craig Unit 2, Colstrip Unit 3, or Colstrip Unit 4 with the same Exit Date as the date set forth in the table above and PacifiCorp does not effectuate Closure by such date, Oregon may elect, at its option, to:

- Continue to take an allocation and assignment of the costs and benefits of such unit for one additional year following the specified Exit Date; or
- Discontinue taking an allocation and assignment of the costs and benefits of such unit as of the specified Exit Date.

Under either election, Oregon will continue to be subject to an allocation of actual Decommissioning Costs if Closure of the unit is effectuated within such one-year period. If Closure of the unit is not effectuated within such one-year period, Oregon will be allocated Decommissioning Costs based on the estimates established pursuant to Section 4.3.

Oregon will be allocated actual Decommissioning Costs if Closure of Cholla Unit 4 occurs on or before January 1, 2023. If Cholla Unit 4 operates beyond January 1, 2023, Oregon will be allocated only estimated Decommissioning Costs as of January 1, 2023.

4.1.3.2. Coal-Fueled Interim Period Resources Operated by PacifiCorp, Oregon Exit Through 2027

The Oregon Parties and the Company agree to recommend to the Oregon Commission that the Exit Date for each coal-fueled Interim Period Resource shown in the following table should be used in Oregon for establishing Oregon's Exit Dates and Oregon depreciable lives for these coal-fueled Interim Period Resources, subject to the other provisions of this Section 4.1.

Coal-Fueled Interim Period Resource	Recommended Oregon Exit Date
Jim Bridger 1	December 31, 2023
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
Dave Johnston 1	December 31, 2027
Dave Johnston 2	December 31, 2027
Dave Johnston 3	December 31, 2027
Dave Johnston 4	December 31, 2027

Oregon Parties and the Company will strive to have Exit Orders issued on or before December 15, 2020, for the coal-fueled Interim Period Resources reflected in the table above to allow the Company to make filings in the other States in accordance with Section 4.2. If PacifiCorp effectuates Closure for any of the units no later than the dates in the table above, then the provisions of 4.1.1 will apply.

4.1.3.3. Coal-Fueled Interim Period Resources, Oregon Exit Date 2028 - 2029

The Oregon Parties and the Company agree that the recommended Exit Dates for the coal-fueled Interim Period Resources shown in the following table should be used in Oregon for establishing Oregon's Exit Dates and Oregon depreciable lives for these coal-fueled Interim Period Resources for purposes of this Agreement, subject to the other provisions of this Section 4.1.

Coal-Fueled Interim Period Resource Name	Recommended Oregon Exit Date
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

Oregon Parties and the Company will strive to have Exit Orders issued by the Oregon Commission issued by December 31, 2023, for the coal-fueled Interim Period Resources reflected in the table above to allow the Company to make the necessary filings in other States in accordance with Section 4.2. If PacifiCorp effectuates Closure for any of the units no later than the dates in the table above, then the provisions of 4.1.1 will apply.

4.1.4. Washington Exit Orders

The Washington Clean Energy Transformation Act ("CETA") requires coal-fueled Interim Period Resources to be out of Washington rates by December 31, 2025. Section 6.4 of the Framework Issues addressing Limited Realignment is intended to facilitate the removal of coal-fueled Interim Period Resources from Washington rates and address the Washington-allocated share, per the System Generation-Fixed (“SGF”) Factor, as defined in Appendix C, of all coal-fueled Interim Period Resources whether or not those resources are included in Washington rates.

Washington Commission approval of the 2020 Protocol will constitute an Exit Order for

Washington, unless modified by Reassignment or Limited Realignment, with an Exit Date of December 31, 2023, for Jim Bridger Unit 1, and December 31, 2025, for Jim Bridger Units 2-4 and Colstrip Unit 4. PacifiCorp and the Washington Parties agree that an Exit Order is not required from the Washington Utilities and Transportation Commission for any coal-fueled Interim Period Resources not currently in Washington rates, and PacifiCorp can evaluate seeking Reassignment upon approval of the 2020 Protocol by the Washington Commission.

4.1.5. Establishment of Exit Dates for Hayden Units 1 and 2

On or before February 1, 2021, the Company will make State-specific recommendations to Commissions for the treatment of Hayden Units 1 and 2. If PacifiCorp effectuates Closure for Hayden Units 1 and 2, then the provisions of 4.1.1 will apply, subject to applicable legal requirements.

4.2. Reassignment of Coal-Fueled Interim Period Resources

4.2.1 Company Proposals for Reassignment

After receipt of any Exit Order, PacifiCorp shall analyze whether it is reasonable to continue to operate the affected coal-fueled Interim Period Resource for customers in one or more of the States without Exit Orders. PacifiCorp may propose Reassignment of a greater share of the coal-fueled Interim Period Resource to such State(s) to match State load and resource balance, or request issuance of an Exit Order.[9] PacifiCorp shall provide its analysis to Parties in each applicable State and may make a filing with the Commission in each State that, as yet, has not entered an Exit Order for such coal-fueled Interim Period Resource consistent with the timeframes set forth in Sections 4.1 and this Section. If PacifiCorp seeks Reassignment, the analysis shall be accompanied by recommendations as to an anticipated Closure date if Reassignment is accepted

[9] Provided PacifiCorp secures all applicable approvals, PacifiCorp may effectuate Closure of a Resource without requesting issuance of any Exit Order.

for such coal-fueled Interim Period Resource. Recommended Reassignments, if proposed, should include a range of options, including fallback options based on the potential that one Commission may reject PacifiCorp's recommendation while another Commission may accept the primary recommendation. Notwithstanding this Section 4.2.1, realignment of certain Interim Period Resources serving Washington will be determined subject to resolution of the Limited Realignment Framework Issue or Section 4.1.4 as applicable.

4.2.2 Process and Timing

Consistent with Section 4.1, for those coal-fueled Interim Period Resources, with an Exit Date on or before December 31, 2027, the filings including the Company's analysis and recommendations are targeted to occur by February 1, 2021. For those coal-fueled Interim Period Resources with an Exit Date after December 31, 2027, and on or before December 31, 2029, the filings including the Company's analysis and recommendations are targeted to occur by June 30, 2024, for Exit Orders that are received by December 31, 2023. Where possible, PacifiCorp will make such filings concurrently in each State without an Exit Order so that each unit or plant can be analyzed as a whole. To the extent a delay to these targeted filing dates is necessary, the Company will provide notice to the Parties and Commissions explaining the reason and expected filing dates. For coal-fueled Interim Period Resources with Exit Orders with different Exit Dates, the Company will provide its analysis to the States without Exit Orders within six months after the date any Exit Order is issued by any Commission, subject to the provisions of Section 4.1.4 for the Washington Exit Orders.

If PacifiCorp makes filings pursuant to this Section in multiple States without Exit Orders, then within 60 days from the date the last Commission issues an order pertaining to such filings, PacifiCorp will submit a supplemental filing with each Commission in the State(s) without Exit

Orders summarizing the decisions made by each Commission and PacifiCorp's recommendations regarding the implications.

4.2.3 Effects of Commission Decisions Regarding Assignment

If one or more Commissions have entered orders accepting, collectively, one-hundred percent[10] of the cost allocation of a coal-fueled Interim Period Resource beyond any Exit Date, the costs and benefits of the coal-fueled Interim Period Resource after such Exit Date shall be Reassigned to the States in accordance with the approved Reassignment as specified in the applicable Commission Orders. Supplemental filings will reflect the final Reassignment of each coal-fueled Interim Period Resource as a result of the Reassignment process and Commission Orders.

If two or more Commissions have entered orders requesting, collectively, more than one-hundred percent[11] of the cost allocation and associated benefits of a coal-fueled Interim Period Resource beyond any Exit Date, the Company will recommend a pro-rata Reassignment up to one hundred percent in accordance with the approved Reassignment as specified in the applicable Commission Orders. Supplemental filings will reflect this pro-rata treatment of each coal-fueled Interim Period Resource as a result of the pro-rata Reassignment process for further review and approval by the Commissions.

If Commissions do not agree to accept one-hundred percent cost allocation, collectively, of a coal-fueled Interim Period Resource beyond an Exit Date, as part of its supplemental filings, the Company will provide its recommendations on the treatment of any shortfall in the Reassignment

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[10] Based on PacifiCorp's ownership interest in the coal-fueled Interim Resource, whether wholly-owned or jointly-owned.

[11] Based on PacifiCorp's ownership interest in the coal-fueled Interim Resource, whether wholly-owned or jointly-owned.

of a coal-fueled Interim Period Resource or recommendations on capacity reductions through Closures for further Commission consideration.

In the event of either common Exit Dates for all States or Closure as a result of the Reassignment process or other appropriate regulatory proceedings, the provisions of Section 4.1.1 will apply.

4.3. Decommissioning Costs

4.3.1. Process for Determining Decommissioning Cost Allocation

4.3.1.1. Decommissioning Studies

The Company intends to undertake a contractor-assisted engineering study of decommissioning costs and to make best efforts to complete the study by January 15, 2020, to estimate appropriate Decommissioning Cost reserve requirements for the Jim Bridger, Dave Johnston, Hunter, Huntington, Naughton, Wyodak, and Hayden coal-fueled Interim Period Resources. Colstrip will also be included in the contractor-assisted engineering study of decommissioning costs, and the Company will make best efforts to complete that portion of the study by March 15, 2020. The Company will provide the information from the study to the States as a supplemental filing in all applicable depreciation dockets. The study results will be used to inform the Company's recommendation on the amount of Decommissioning Cost responsibility to be allocated to States for coal-fueled Interim Period Resources that States exit at different times. The Company will retain and make available the Decommissioning Studies in future regulatory proceedings.

4.3.1.2. Decommissioning Studies Update

The Company intends to undertake the same process to complete an update to the Decommissioning Studies by no later than June 30, 2024, to estimate appropriate Decommissioning Cost reserve requirements for the Craig, Hunter, Huntington, and Wyodak coal-fueled Interim Period Resources (collectively with the studies discussed in the paragraph above constituting the Decommissioning Studies), which will be incorporated into a Company-sponsored depreciation study. The Company will retain and make available the Decommissioning Studies update in future regulatory proceedings.

4.3.1.3. Commission Determination of Decommissioning Costs

No Party will be bound by the Decommissioning Cost estimates in the Decommissioning Studies undertaken pursuant to Paragraphs 4.3.1.1 and 4.3.1.2, and final determination of each State's just and reasonable Decommissioning Cost allocation for each coal-fueled Interim Period Resource will remain exclusively with each Commission and will be determined in the depreciation dockets in which the Decommissioning Costs are included.[12]

4.3.1.4. Decommissioning Costs Allocation

For coal-fueled Interim Period Resources having a common operating life across all States, each State shall be allocated its share of actual Decommissioning Costs based on either an SG Factor (if closed during the Interim Period) or an Assigned Production ("AP") Factor, adjusted for any Reassignment or Limited Realignment effects (if closed after the Interim Period). For coal-fueled Interim Period Resources that do not have a common operating life across all States, each Exiting State shall be allocated, using either an SG Factor (if closed during the Interim Period) or an AP Factor, adjusted for any Reassignment or Limited Realignment effects (if closed after the Interim Period), that State's share of estimated Decommissioning Costs based on the Decommissioning Studies described in Sections 4.3.1.1 and 4.3.1.2. If the Decommissioning Costs ordered to be included in the reserve balance established for an Exiting State are less than the estimated Decommissioning Costs allocated to that Exiting State as specified above, such

[12] For California, Decommissioning Costs will be addressed in PacifiCorp's next general rate case.

difference shall not be allocated to any other State under any circumstance. If PacifiCorp effectuates Closure of a coal-fueled Interim Period Resource after one or more States have exited from the Resource, the Company may, with the burden of proof and subject to PacifiCorp supporting its proposal in testimony,[13] propose to allocate to and collect from each State that is participating in that Resource at the time of Closure that State's share, based on either an SG Factor (if closed during the Interim Period) or an AP Factor, adjusted for any Reassignment or Limited Realignment effects (if closed after the Interim Period), of actual Decommissioning Costs less the regulatory liabilities for Exiting States including interest as described in Section 4.3.2 and less any difference between the reserve balance established for each Exiting State and the estimated costs allocated to each Exiting State as described above. Parties in such State(s) may take any position regarding a Company request to recover Decommissioning Costs.

4.3.2. Accounting for Decommissioning Costs Reserve Balances when All States Do Not Exit a Unit

After an Exit Date by some but not all States, the estimated Decommissioning Costs reserves allocated to the Exiting State(s) associated with a coal-fueled Interim Period Resource unit, from which that State is exiting, will be accounted for as a regulatory liability that is excluded from rate base. Interest will be accrued on that regulatory liability at the Company's then-authorized weighted average cost of capital[14] for each State that continues to participate in that coal-fueled Interim Period Resource after an Exit Date until the decommissioning work on that unit is completed.

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[13] PacifiCorp's testimony will identify and explain the variances between estimated and actual Decommissioning Costs.
[14] Not to exceed the maximum carrying charge allowed by applicable law or Commission Order.

4.3.3. Accounting for Interim and Final Retirements

Before any State exits a coal-fueled Interim Period Resource, but no later than December 31, 2021, the Company shall propose to the Parties a process for separately accounting for removal costs associated with interim retirements and final Decommissioning Costs in its accounting system. Each State may determine the regulatory treatment for such removal costs in appropriate proceedings.

4.3.4. Individual State Review Process

Any Party, at its discretion and cost, may pursue actions it deems necessary or appropriate to review and evaluate the Decommissioning Studies or Decommissioning Costs and may take any positions based on its review and findings. If a Commission issues an order identifying an independent evaluator for the Decommission Studies, and the Commission Order provides for the deferral and later recovery in rates of the cost of the independent evaluator, the Company agrees to initially pay for this independent evaluation.

4.4. Qualifying Facilities

The allocation of QF PPAs shall be treated in accordance with Sections 4.4.1 and 4.4.2 of this 2020 Protocol, superseding Section (IV)(A)(3) of the 2017 Protocol. For Washington, QF PPAs will be assigned and allocated consistent with the terms of Appendix F during the Interim Period. Other than addressing the allocation of the costs and assignment of benefits of QF PPAs among the States, this 2020 Protocol does not restrict or affect any Commission's jurisdiction over any agreement or interaction between QFs and the Company. QF PPAs shall be treated in the following manner for allocation and assignment purposes.

4.4.1. Existing QF PPAs

QF PPAs fully executed[15] or as to which a legally enforceable obligation exists[16] on or before December 31, 2019 ("Existing QF PPAs") will remain system assigned and allocated, subject to any Limited Realignment in Section 6.4, until the end of 2029, after which time they will be situs assigned and allocated to the State having jurisdiction over the QF PPA for avoided cost pricing (“State of Origin”).

4.4.1.1. Wyoming QF Adjustment

The Company agrees to include: (1) a $5 million adjustment, annually, to reduce Net Power Costs in Wyoming customer rates[17] beginning January 1, 2021, until December 31, 2022; and (2) a $7.175 million adjustment, annually, to reduce Net Power Costs in Wyoming customer rates from January 1, 2023, until December 31, 2029.[18] This adjustment will terminate on or before December 31, 2029, or upon issuance of any order by the Wyoming Commission that changes Wyoming’s treatment of the Implemented Issues or the Resolved Issues from the terms of the 2020 Protocol. The adjustment shall be made solely at the Company’s expense and not allocated to any other States.

4.4.2. New QF PPAs

QF PPAs fully executed or as to which a legally enforceable obligation exists after December 31, 2019, (“New QF PPAs”) will be situs assigned and allocated for ratemaking proceedings pertaining to periods beginning on or after January 1, 2020, to the State of Origin.

[15] Fully executed means executed and delivered by each party to the other party.
[16] Any such legally enforceable obligation date must be confirmed by an order from the applicable Commission issued prior to the end of the Interim Period.
[17] The Wyoming QF adjustment will be included in the base ECAM costs forecasted in a general rate case with rates effective on or after January 1, 2021. The Wyoming QF adjustment will be trued up in the ECAM at 100% (sharing-bands do not apply).
[18] The Wyoming QF adjustment shall be removed from base ECAM costs on December 31, 2029, or as otherwise specified in Section 4.4.1.1, so that no adjustment flows through to customers in rates after that date unless it was deferred in the ECAM prior to December 31, 2029.

4.4.2.1. Interim Period Treatment – Pre-Nodal Pricing Model

For the Interim Period, the energy output of New QF PPAs will be dynamically allocated per this agreement using the SG Factor, priced at a forecasted reasonable energy price defined below, and any cost of a New QF PPA above the forecasted reasonable energy price will be situs assigned and allocated to the State of Origin. The forecasted reasonable energy price is a single blended market price derived from the Company's Official Forward Price Curve ("OFPC"), scaled for hourly prices, that was used for setting QF pricing for the New QF PPA. The single blended market price is calculated by applying the appropriate weighting to the hourly scaled prices from the OFPC for each market hub. The weightings per market hub are identified in the table below. The weighting will be applied by month and by heavy load hours ("HLH") and light load hours ("LLH"). The forecasted reasonable energy price, used for allocation purposes, shall be established at the time a QF PPA is fully executed.

Market Hub Weighting by Month - HLH												
Market	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
COB	0.00%	0.55%	1.34%	0.82%	3.45%	4.01%	8.41%	3.69%	8.58%	0.97%	1.79%	1.20%
Mid Columbia	24.42%	30.21%	55.74%	63.22%	70.84%	87.39%	81.05%	83.85%	75.88%	42.27%	34.30%	40.74%
Palo Verde	1.52%	2.53%	1.07%	0.66%	0.54%	0.03%	0.76%	1.89%	1.85%	2.55%	3.45%	0.30%
Four Corners	64.72%	58.68%	35.94%	27.40%	16.15%	5.75%	4.12%	2.17%	3.82%	45.79%	52.88%	44.47%
Mead	0.18%	0.13%	1.23%	1.46%	1.52%	1.74%	1.95%	3.30%	6.64%	0.33%	0.12%	0.57%
Mona	9.16%	7.90%	2.94%	2.03%	1.79%	0.74%	0.01%	0.18%	1.82%	7.82%	7.46%	2.18%
NOB	0.00%	0.00%	1.75%	4.40%	5.72%	0.33%	3.70%	4.92%	1.41%	0.27%	0.00%	10.54%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Market Hub Weighting by Month - LLH												
Market	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
COB	0.00%	0.99%	5.17%	3.53%	15.50%	15.16%	5.97%	1.21%	0.31%	2.43%	3.44%	1.16%
Mid Columbia	58.74%	60.10%	76.58%	66.36%	71.82%	80.41%	85.52%	92.26%	83.27%	62.78%	66.30%	59.09%
Palo Verde	0.00%	1.12%	0.42%	0.04%	0.39%	0.40%	2.71%	3.04%	0.00%	0.92%	1.91%	2.30%
Four Corners	33.45%	34.66%	13.63%	26.49%	10.44%	3.30%	5.35%	2.39%	11.60%	27.69%	26.36%	29.65%
Mead	0.00%	0.06%	0.94%	0.44%	0.93%	0.47%	0.25%	0.00%	0.00%	0.57%	0.00%	0.00%
Mona	7.81%	3.07%	1.54%	2.41%	0.92%	0.27%	0.00%	1.11%	4.82%	5.61%	1.99%	7.80%
NOB	0.00%	0.00%	1.71%	0.73%	0.00%	0.00%	0.20%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

4.4.2.2. Post-Interim Period Treatment

After the conclusion of the Interim Period, assuming resolution and Commission approval of all Framework Issues, the Parties agree that New QF PPAs will be situs assigned and the costs and benefits will be allocated and assigned per the methodology developed through the Framework process in Section 6.2.

5. Resolved Issues - Post-Interim Period Implementation

The Parties agree, conditioned upon reaching agreement on a Post-Interim Period Method on the future allocation treatment described in this Section 5 for certain benefits, revenues, costs, and investments. As stated in Section 2, these Resolved Issues of the 2020 Protocol are intended to take effect with the implementation of the Post-Interim Period Method. Parties acknowledge that conditions may change materially in unforeseen ways during the Interim Period and that it may be necessary to re-evaluate Resolved Issues as part of the Post-Interim Period Method. The Resolved Issues are identified below.

5.1. Generation Costs

Following the Interim Period, a fixed share of the Interim Period Resources will be assigned to serve load in each State. The costs and benefits, including environmental attributes, associated with each Interim Period Resource will be allocated and assigned in accordance with the Interim Period Resources fixed allocation provisions (Section 5.1.1), Reassignment of coal-fueled Interim Period Resources (Section 4.2), and Limited Realignment (Section 6.4).

5.1.1. Interim Period Resources Fixed Allocation

Interim Period Resources will be assigned and allocated to States based on the SGF Factor for each State as defined in Appendix C. The load information used to determine the SGF Factor is subject to modification for the inclusion or exclusion of Special Contract loads as determined through the Framework process for resolution of issues addressed in Section 6.3. The SGF Factor is used to develop the AP Factor for each unit. Additionally, Interim Period Resources will be subject to the Limited Realignment as outlined in Section 6.4 and the Reassignment of Interim

Period Resources as outlined in Section 4.2. Any such Assignment of Interim Period Resources, along with the Limited Realignment and the Reassignment of Interim Period Resources, will be subject to the following:

- Accumulated depreciation for Interim Period Resources will be allocated per the AP Factor. State-specific accumulated depreciation that has been tracked by the Company due to increased depreciation expenses will be treated as situs to the State and offset its Resource costs until that State exits from an Interim Period Resource.
- Accumulated deferred income taxes and excess deferred income taxes will be allocated per the Company's tax software system, using the AP Factor. State-specific accumulated deferred income taxes and excess deferred income taxes that have been tracked by the Company due to increased depreciation expense will be treated as situs to the State and offset that State's Resource costs until that State exits from an Interim Period Resource.
- All O&M expenses that are associated with a specific Interim Period Resource will be allocated per the AP Factor.
- All generation-related O&M expenses that cannot be allocated to a specific Interim Period Resource through an AP Factor, such as general office generation management expenses, will be allocated to States based on an Assigned Production Operations and Maintenance ("APOM") Factor, calculated as each States' relative share of direct-allocated generation O&M expenses. There will be three separate APOM factors based on FERC classifications, with the APOMS used for steam generation (FERC accounts 500 - 514), APOMH used for hydro generation (FERC accounts 535-545) and APOMO used for other generation (FERC accounts 546 -

554). The APOM factor calculations are shown in Appendix C and also included in Appendix B, Column 5.

- Property tax will continue to be allocated based on gross plant using the GPS Factor as calculated in Appendix C and included in Appendix B, Column 5.
- All other rate-base items associated with Interim Period Resources will be allocated consistent with the Interim Period Resource allocations using the AP Factor.

5.1.2. New Resources Fixed Assignment

New Resources include any Resources that are not in commercial operation before the end of the Interim Period. All costs and benefits associated with new Resources, subject to the qualification below, will be allocated and assigned to States based on a fixed assignment under the process to be determined in Section 6.1 – Resource Planning and New Resource Assignment. The Parties agree that a transitional period is necessary to change the cost allocation for future new Resources that are planned for by the Company, and that any new Resource reaching commercial operation before the end of the Interim Period will be treated the same as Interim Period Resources for allocation purposes under the terms of this Agreement.

5.2. Transmission Costs

The costs associated with transmission assets, except as addressed in Section 6.1, will be dynamically allocated among States on the System Transmission ("ST") Factor, generally calculated based on a classification of costs as 75 percent Demand-Related and 25 percent Energy-Related, and based on twelve monthly Coincident Peaks, using weather-normalized retail peak and energy data, as more thoroughly defined in Appendix C.

All revenues recovered through PacifiCorp's Open Access Transmission Tariff or other transmission rate schedules approved by the FERC will be allocated based on the ST Factor.

The 2020 Protocol does not preclude PacifiCorp from participating in any independent transmission organization, regional transmission organization, or other similar wholesale transmission market subject to the jurisdiction and oversight of the FERC.

5.3. Distribution Costs

All distribution-related expenses and capital costs that can be directly allocated will be directly allocated to the States where the related distribution facilities are located. Those distribution expenses that cannot be directly allocated will be allocated among States on a System Net Plant Distribution ("SNPD") factor, as shown in Appendix B.

5.4. System Overhead Costs

Costs that support more than one function, such as generation, transmission, or distribution plant, will continue to be allocated on the System Overhead (“SO”) Factor after the Interim Period but will be calculated based on an equal one-third weighting of the System Capacity (“SC”) Factor, System Energy Factor, and System Gross Plant Distribution (“SGPD”) Factor, as shown in Appendix B.

5.5. Administrative and General Costs

Administrative and General Costs, General Plant costs, and Intangible Plant costs, both expenses and investments, which can be directly allocated will be directly allocated to the appropriate State(s). Those costs that cannot be directly allocated will be allocated among States consistent with the factors set forth in Appendix B.

5.6. Other Allocation Issues

Items included in the Company's results of operations, other than those that are specifically called out herein, will continue to be allocated on the same factors used in the 2017 Protocol. The

FERC account and allocation factor combinations are included in Appendix B. The algebraic derivation and factor definitions are included in Appendix C.

The following miscellaneous changes will be made to be consistent with the other allocation changes:

- Communication equipment allocated on the System Generation Factor during the Interim Period will change to either the SE Factor (generation-related) or ST Factor (transmission-related) depending on the nature of the equipment for which the communication equipment is utilized.
- Contributions In Aid of Construction ("CIAC") currently allocated on the SG Factor will change to either the AP factor for generation-related CIAC or the ST Factor for transmission related CIAC.
- Generation-related dispatch costs and associated plant will be allocated on the SE Factor.
- Miscellaneous regulatory assets and liabilities, and miscellaneous deferred debits will be allocated with the appropriate allocation factor depending on the related assets or underlying costs. Miscellaneous regulatory assets and liabilities, and miscellaneous deferred debits currently allocated on the SG Factor, will change to the AP Factor for generation-related and ST Factor for transmission-related items.

Taxes and fees will be allocated as follows:

- Income taxes will be calculated using the federal tax rate and PacifiCorp's combined State effective tax rate. State specific Schedule M and deferred income tax amounts will be allocated using the Company's tax software system. Consistent with prior system allocation methods, the Washington Public Utility Tax is allocated using the SO Factor in lieu of a Washington income tax.

- Franchise taxes, revenue related taxes, Commission assessments and fees, and usage related taxes are situs or a pass through.
- Property taxes are system allocated based on gross plant and allocated on the GPS Factor.
- Generation and fuel related taxes will follow the assignment of the Resource.
- Other taxes such as payroll taxes are embedded in the cost of expense or capital.

Balances associated with the Trojan Decommissioning will be allocated using the Trojan Decommissioning Fixed ("TROJDF") Factor. This will not affect State-specific treatment of this item.

5.7. Demand-Side Management Programs

Costs associated with DSM Programs, including Class 1 DSM Programs, will continue to be allocated on a situs basis to the State in which the investment is made. The benefits from these programs will flow back to the State through Net Power Costs or through reduced or delayed future capacity needs that will be addressed in the development and implementation of the process identified in Section 6.1.

5.8. State-Specific Initiatives

Costs and benefits resulting from a State-specific initiative will continue to be allocated and assigned on a situs basis to the State adopting the initiative. Historically, these have included, but are not limited to, programs such as incentive programs and customer and community energy generation programs, but have not included local fees or taxes related to the ongoing operation of existing transmission and generation facilities within a State. As new issues arise, PacifiCorp will bring each issue to the MSP Workgroup to discuss whether each issue is a State-specific initiative, and, if not, whether a different allocation method is appropriate.

6. Framework Issues

The Parties acknowledge that certain components of the Post-Interim Period Method are not resolved by this Agreement, including Resource Planning and new Resource Assignment, Net Power Costs / Nodal Pricing Model, the treatment of Special Contracts, post-Interim Period capital additions, and other issues related to the transition from a dynamically-allocated system generation portfolio to fixed generation portfolios. As part of the 2020 Protocol, the Parties agree to the following processes and timeframes to address remaining, unresolved Framework Issues and to request approval of a new Post-Interim Period Method agreement by the Commissions. The Company will file for Commission consideration and approval of a new Post-Interim Period Method in accordance with Section 2. The general understanding reached by the Parties as to process and timelines for Framework Issues is as follows.

6.1. Resource Planning and New Resource Assignment

Continued operation, planning, and dispatch of the Company's system as an integrated six-State system, to the greatest extent practicable, will likely be beneficial to PacifiCorp's customers. However, because of differing State policies requiring or excluding certain generation resources, it appears infeasible to continue serving customers with a common generation portfolio and dynamically allocating system costs. Continued dynamic allocation of all system costs in this environment could result in increased costs for some States, if not all. Accordingly, allocating costs and assigning benefits associated with generation capacity will require assignment of specific Resources, and potentially certain transmission assets, to a specific State or States. The goal is to allow PacifiCorp to meet its legal requirements as a public utility in each State in a risk-adjusted, least-cost manner, while striving to mitigate cost impacts to other States.

PacifiCorp will continue to plan for capacity and operating needs, both for the entire interstate system and for each State. PacifiCorp will work with Parties to develop:

- A planning process that optimizes risk-adjusted, least-cost resource portfolios on a system basis to the extent practicable, while meeting individual State requirements and maintaining system reliability; and
- A process that assigns benefits and allocates costs of specific new Resources added in order to meet an individual State's needs.

Parties will evaluate these processes in light of existing or new Commission regulatory processes governing Resource planning, procurement, and investment approval.

6.2. Net Power Costs / Nodal Pricing Model ("NPM")

A method to track the costs and benefits of Resource portfolios which may differ for each State will be necessary in the future to maintain the benefits of system dispatch as much as practicable. Specifically, after the Interim Period when States may no longer participate in a common Resource portfolio, a NPM may be used to track cost causation and receipt of benefits by each State for rate-making purposes.

Consistent with and in consideration of the Nodal Pricing Model Memorandum of Understanding in Appendix D, the Company agreed to begin the development of an NPM with a third-party vendor and will use best efforts to implement the NPM by the end of January 2021, for purposes of total-Company day-ahead scheduling. Parties intend for this to provide some time and experience with the NPM before it may be used for rate making as part of the Post-Interim Period Method.[19]

The Company will also use best efforts to implement a model that can forecast NPC based on the NPM concept. During the Interim Period, this model may be used by the Company for forecast analysis of NPC. After the Interim Period, the Company intends to propose the use of this model for NPC forecasts in applicable rate-making proceedings.

6.3. Special Contracts

The Company will continue to work in good faith with the Special Contract customers to develop one or more proposals for consideration by the Parties on the treatment of Special Contracts' loads, costs, and benefits as part of the Framework Issues and will make best efforts to present a proposal to Parties by September 1, 2021, with the intention of incorporating such proposal into the Post-Interim Period Method.

6.4. Limited Realignment

The Parties agree to investigate during the Interim Period the potential Limited Realignment of Interim Period Resources among the States. Limited Realignment is intended to address, among other potential issues, the transition of Washington retail customers away from coal-fueled Interim Period Resource in compliance with the Washington CETA by realigning Interim Period Resources, including natural gas-fueled Interim Period Resources.

6.5. Post-Interim Period Capital Additions – Coal-Fueled Interim Period Resources

For a coal-fueled Interim Period Resource for which one or more States have an Exit Date that differs from the depreciable life or Exit Date ordered in any other State, a process is needed

[19] NPM is intended to be used for total Company system dispatch when it is fully functional and operational and will impact system Net Power Costs that flow through State NPC balancing accounts.

for determining the cost allocation for capital investments made in the Resources subsequent to the Interim Period and prior to the Exit Date for each State. The Parties have agreed to evaluate, but have not accepted, the following Company straw proposal for post-Interim Period capital investments, information about which is provided here not for Commission approval but to inform future discussions.

6.5.1. PacifiCorp Straw Proposal - Post-Interim Period Capital Investment Allocation Exceptions

For post-Interim Period incremental capital investments that are made primarily for the purpose of extending the life of a coal-fueled Interim Period Resource beyond a State's Exit Date for that Resource, including but not limited to those associated with achieving compliance with environmental requirements or those necessitated by catastrophic failure, such investments would not be allocated to States that have issued such Exit Orders and would be allocated based on the percentage shares of the coal unit Reassignment process addressed in Section 4.2 or as otherwise determined for States that continue to participate in the coal-fueled Interim Period Resource.

For these incremental capital investments made primarily for the purpose of repairing a coal-fueled Interim Period Resource following a catastrophic failure of the Interim Period Resource, such investments would not be allocated to and no generation or benefits will be assigned to States that have issued Exit Orders for that Resource. Parties in States not allocated costs for such investments would support recovery of any remaining net book value and Decommissioning Costs.

6.5.2. PacifiCorp Straw Proposal - Incremental Capital Investments Made Between 2024 and the Exit Date Where Exit Date is On or Before December 31, 2027

For States with Exit Orders for a coal-fueled Interim Period Resource specifying an Exit Date on or before December 31, 2027, capital investments made in such Interim Period Resource after the Interim Period and prior to the Exit Date, would be allocated to an Exiting State based on the AP Factor, adjusted for any Limited Realignment impacts agreed to, and pro-rated for the number of years remaining based on the longest life ordered in any State's depreciation docket or rate case by December 31, 2020, for such Interim Period Resource. States without Exit Orders in such Interim Period Resource would be allocated the remaining amount of capital investment based on proportional shares of the AP factor for the States that will be participating in the coal-fueled Interim Period Resource after an Exit Date. For example, if a State's Exit Order establishes an Exit Date four years from the date the capital investment is in-service, and the Interim Period Resource has the longest remaining life in another State of ten years, the State with the Exit Order would be allocated four-tenths of that State's share of the cost of the qualifying capital investment. Each State's allocation of such capital investments would be subject to a prudence review based on the cost to be allocated to each State consistent with this Section.

6.5.3. PacifiCorp Straw Proposal - Incremental Capital Investments Made in 2024 and 2025 Where Exit Date is After 2027

For States with Exit Orders for a coal-fueled Interim Period Resource specifying an Exit Date after 2027, capital investments made in such Interim Period Resource after the Interim Period and through December 31, 2025, would be allocated to all States based on the AP Factor, adjusted for any Limited Realignment impacts agreed to, and prudence of such capital investments for States with Exit Orders would be determined based on the life established for such Interim Period Resource in the Exit Order. This would allow for the reasonable allocation of capital and operating costs for the Interim Period Resource during a period of time while PacifiCorp pursues the process established in Section 4.2.

6.5.4. PacifiCorp Straw Proposal - Incremental Capital Investments Made Between 2026 and the Exit Date Where the Exit Date is After 2027

For States with Exit Orders for a coal-fueled Interim Period Resource specifying an Exit Date after 2027, capital investments made in such Interim Period Resource after December 31, 2025, and until the Exit Date, would be allocated to an Exiting State based on the AP Factor, adjusted for any Limited Realignment impacts agreed to, and pro-rated for the number of years remaining based on the longest life ordered in any State's depreciation docket, Reassignment proceeding, or rate case as of December 31, 2025. States that will be participating in the coal-fueled Interim Period Resource after an Exit Date would be allocated the remaining amount of any capital investment based on the AP Factor calculated for that coal-fueled Interim Period Resource.

7. Allocation of Gain or Loss from Sale of Assets

Any gain or loss from the sale of Company-owned assets will be allocated among or to States based upon the proportional allocation or assignment of the asset at the time of the execution date of the sale agreement. Each Commission will determine the appropriate allocation of the gain or loss allocated to that State as between PacifiCorp's customers and shareholders. For assets that have been Reassigned for less than one calendar year as of the execution date of the sale agreement, States will be allocated the gain or loss as if the asset had remained a System Resource.

8. Interpretation and Governance

8.1. Issues of Interpretation

Parties will attempt, consistent with their legal obligations, to resolve questions of interpretation of the 2020 Protocol, in good faith in light of the language of the 2020 Protocol and the intent of the Parties.

8.2. Workgroups

8.2.1. Framework Issues Workgroup

PacifiCorp will schedule and convene meetings with Parties to continue negotiations of the Framework Issues, which may occur in person or remotely.

8.2.2. Multi-State Process Workgroup

Consistent with Sections 8.4 or 8.5 of this Agreement, the Company will notify Parties and other MSP participants if it determines a need exists to convene the MSP Workgroup to address general allocation issues or complaints related to the 2020 Protocol. Any Party to this Agreement, State utility regulatory agency, or other stakeholder can participate in the MSP Workgroup. The MSP Workgroup may create sub-committees to investigate or evaluate or make recommendations as to specified issues. MSP Workgroup meetings may be held in person or remotely.

8.3. Commissioner Forum

The 2017 Protocol included a mandatory requirement to hold an annual Commissioner Forum each January during the pendency of that agreement. Under this 2020 Protocol, Commission Forums are not required. A Commission or the MSP Workgroup may request such a meeting of Commissioners. If a Commissioner Forum is requested, all seated commissioners from each State will be invited to participate. Commissioner Forums will be public meetings, and all interested parties will be allowed to attend. Before attending a Commissioner Forum, each Commission can take such steps and provide such process for public input as the Commission determines is necessary or appropriate under applicable State laws.

8.4. Proposals to Change the 2020 Protocol during the Interim Period

The Parties agree not to propose or support changes to the 2020 Protocol applicable to the Interim Period based on a Party's dissatisfaction with a reasonably foreseeable outcome from implementation of the 2020 Protocol. Before proposing an alternative or modification to the 2020

Protocol based primarily on changed or unforeseen circumstances, each Party agrees to first make the proposal to the Parties and attempt in good faith to resolve the concern before asking a Commission to change the 2020 Protocol. The provisions of this Section 8.4 will apply to any State agency only to the extent consistent with the State agency's statutory obligations.

Proposals for modifications to the 2020 Protocol may be submitted to the Company by any Party. Proposals received by the Company shall be circulated in a timely manner to the other Parties and the Company shall initiate discussions to attempt to address and resolve specific concerns.

8.5. Replacement of the 2020 Protocol

If any stakeholder that is not a Party to this Agreement objects to the use of the 2020 Protocol after approval by the Commissions or proposes a new inter-jurisdictional allocation procedure, PacifiCorp may convene the MSP Workgroup and hold discussions to attempt to address and resolve the concerns at an MSP Workgroup meeting(s).

8.6. Interdependency Among Commission Approvals

The 2020 Protocol has been developed and negotiated by the Parties as an integrated, interdependent whole. Support by any Party of the 2020 Protocol is expressly conditioned upon approval without material alteration of the 2020 Protocol by all Commissions in the States that PacifiCorp has sought approval.[20] If any Commission disapproves, alters, or conditions approval of the 2020 Protocol, Parties shall promptly meet and discuss the implications of that Commission's action. PacifiCorp shall report to the Parties any Commission Order of another State concerning the 2020 Protocol. Parties agree to recommend to each Commission that approval of the 2020 Protocol be conditioned on other Commissions approving the 2020 Protocol without change.

[20] California has historically reviewed allocation methodologies in conjunction with a general rate case. PacifiCorp's next regulatory-mandated general rate case will not be filed until 2021 at the earliest.

9. Compliance with Resource Laws

PacifiCorp asserts that the 2020 Protocol complies with the requirements of current resource laws of all of the States and will not shift risk of compliance among PacifiCorp's States. If a future change in law, court decision, or Commission decision results in the Company's reasonable belief that compliance with all applicable laws cannot be achieved, the Company will raise its concerns with the Parties and/or convene an MSP Workgroup meeting to address the issue.

10. Signatures of Parties to the 2020 Protocol

This 2020 Protocol is entered into by each Party on the date entered below such Party's signature.

PACIFICORP By: ______________ Title: Senior Vice President, Strategic Business Planning Date: November 22, 2019	ALLIANCE OF WESTERN ENERGY CONSUMERS By: ______________ Title: ______________ Date: ______________
IDAHO CONSERVATION LEAGUE By: ______________ Title: ______________ Date: ______________	IDAHO PUBLIC UTILITIES COMMISSION STAFF By: ______________ Title: ______________ Date: ______________

9. Compliance with Resource Laws

PacifiCorp asserts that the 2020 Protocol complies with the requirements of current resource laws of all of the States and will not shift risk of compliance among PacifiCorp's States. If a future change in law, court decision, or Commission decision results in the Company's reasonable belief that compliance with all applicable laws cannot be achieved, the Company will raise its concerns with the Parties and/or convene an MSP Workgroup meeting to address the issue.

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This 2020 Protocol is entered into by each Party on the date entered below such Party's signature.

PACIFICORP By: Title: Senior Vice President, Strategic Business Planning Date: November 22, 2019	ALLIANCE OF WESTERN ENERGY CONSUMERS By: Title: Attorney Date: 11/25/19
IDAHO CONSERVATION LEAGUE By: Title: Date:	IDAHO PUBLIC UTILITIES COMMISSION STAFF By: Title: Date:

9. Compliance with Resource Laws

PacifiCorp asserts that the 2020 Protocol complies with the requirements of current resource laws of all of the States and will not shift risk of compliance among PacifiCorp's States. If a future change in law, court decision, or Commission decision results in the Company's reasonable belief that compliance with all applicable laws cannot be achieved, the Company will raise its concerns with the Parties and/or convene an MSP Workgroup meeting to address the issue.

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PACIFICORP By: __________ Title: Senior Vice President, Strategic Business Planning Date: November 22, 2019	ALLIANCE OF WESTERN ENERGY CONSUMERS By: __________ Title: __________ Date: __________
IDAHO CONSERVATION LEAGUE By: __________ Title: Energy Associate Date: November 27 2019	IDAHO PUBLIC UTILITIES COMMISSION STAFF By: __________ Title: __________ Date: __________

9. Compliance with Resource Laws

PacifiCorp asserts that the 2020 Protocol complies with the requirements of current resource laws of all of the States and will not shift risk of compliance among PacifiCorp's States. If a future change in law, court decision, or Commission decision results in the Company's reasonable belief that compliance with all applicable laws cannot be achieved, the Company will raise its concerns with the Parties and/or convene an MSP Workgroup meeting to address the issue.

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This 2020 Protocol is entered into by each Party on the date entered below such Party's signature.

PACIFICORP By: Title: Senior Vice President, Strategic Business Planning Date: November 22, 2019	ALLIANCE OF WESTERN ENERGY CONSUMERS By: Title: Date:
IDAHO CONSERVATION LEAGUE By: Title: Date:	IDAHO PUBLIC UTILITIES COMMISSION STAFF By: Terri Carlock Title: Administrator Utilities Division Date: 11/26/2019

EXECUTION VERSION

IDAHO IRRIGATION PUMPERS ASSOCIATION By: Eric L. Olsen Title: Attorney Date: 12/2/19	INTERWEST ENERGY ALLIANCE By: __________ Title: __________ Date: __________
MONSANTO COMPANY By: __________ Title: __________ Date: __________	NORTHWEST & INTERMOUNTAIN POWER PRODUCERS By: __________ Title: __________ Date: __________
NORTHWEST ENERGY COALITION By: __________ Title: __________ Date: __________	__________ By: __________ Title: __________ Date: __________
OREGON CITIZENS' UTILITY BOARD By: __________ Title: __________ Date: __________	OREGON PUBLIC UTILITY COMMISSION STAFF By: __________ Title: __________ Date: __________

EXECUTION VERSION

IDAHO IRRIGATION PUMPERS ASSOCIATION By: __________ Title: __________ Date: __________	INTERWEST ENERGY ALLIANCE By: Lisa Tormoen Hickey Title: Regulatory Attorney Tormoen Hickey LLC Date: 12/2/19
MONSANTO COMPANY By: __________ Title: __________ Date: __________	NORTHWEST & INTERMOUNTAIN POWER PRODUCERS By: __________ Title: __________ Date: __________
NORTHWEST ENERGY COALITION By: __________ Title: __________ Date: __________	__________ By: __________ Title: __________ Date: __________
OREGON CITIZENS' UTILITY BOARD By: __________ Title: __________ Date: __________	OREGON PUBLIC UTILITY COMMISSION STAFF By: __________ Title: __________ Date: __________

IDAHO IRRIGATION PUMPERS ASSOCIATION By: __________ Title: __________ Date: __________	INTERWEST ENERGY ALLIANCE By: __________ Title: __________ Date: __________
MONSANTO COMPANY By: Randall C. Budge Title: Attorney for Monsanto Date: 11/26/2019	NORTHWEST & INTERMOUNTAIN POWER PRODUCERS By: __________ Title: __________ Date: __________
NORTHWEST ENERGY COALITION By: __________ Title: __________ Date: __________	__________ By: __________ Title: __________ Date: __________
OREGON CITIZENS' UTILITY BOARD By: __________ Title: __________ Date: __________	OREGON PUBLIC UTILITY COMMISSION STAFF By: __________ Title: __________ Date: __________

EXECUTION VERSION

IDAHO IRRIGATION PUMPERS ASSOCIATION By: __________ Title: __________ Date: __________	INTERWEST ENERGY ALLIANCE By: __________ Title: __________ Date: __________
MONSANTO COMPANY By: __________ Title: __________ Date: __________	NORTHWEST & INTERMOUNTAIN POWER PRODUCERS By: __________ Title: __________ Date: __________
NORTHWEST ENERGY COALITION By: __________ Title: __________ Date: __________	__________ By: __________ Title: __________ Date: __________
OREGON CITIZENS' UTILITY BOARD By: [signature] Title: Executive Director Date: 11/26/2019	OREGON PUBLIC UTILITY COMMISSION STAFF By: __________ Title: __________ Date: __________

EXECUTION VERSION

IDAHO IRRIGATION PUMPERS ASSOCIATION By: ________ Title: ________ Date: ________	INTERWEST ENERGY ALLIANCE By: ________ Title: ________ Date: ________
MONSANTO COMPANY By: ________ Title: ________ Date: ________	NORTHWEST & INTERMOUNTAIN POWER PRODUCERS By: ________ Title: ________ Date: ________
NORTHWEST ENERGY COALITION By: ________ Title: ________ Date: ________	________ By: ________ Title: ________ Date: ________
OREGON CITIZENS' UTILITY BOARD By: ________ Title: ________ Date: ________	OREGON PUBLIC UTILITY COMMISSION STAFF By: [signature] Title: Assistant Attorney General Date: 11/25/19

EXECUTION VERSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS By: Rand L Willi Title: Attorney Date: 11-29-2019	PACKAGING CORPORATION OF AMERICA By: __________ Title: __________ Date: __________
POWDER RIVER BASIN RESOURCE COUNCIL By: __________ Title: __________ Date: __________	RENEWABLE NORTHWEST By: __________ Title: __________ Date: __________
SIERRA CLUB By: __________ Title: __________ Date: __________	UTAH ASSOCIATION OF ENERGY USERS By: __________ Title: __________ Date: __________
UTAH CLEAN ENERGY By: __________ Title: __________ Date: __________	UTAH DIVISION OF PUBLIC UTILITIES By: __________ Title: __________ Date: __________

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS By: ______________ Title: ______________ Date: ______________	PACKAGING CORPORATION OF AMERICA By: ______________ Title: ______________ Date: ______________
POWDER RIVER BASIN RESOURCE COUNCIL By: ______________ Title: Staff Attorney Date: November 26, 2019	RENEWABLE NORTHWEST By: ______________ Title: ______________ Date: ______________
SIERRA CLUB By: ______________ Title: ______________ Date: ______________	UTAH ASSOCIATION OF ENERGY USERS By: ______________ Title: ______________ Date: ______________
UTAH CLEAN ENERGY By: ______________ Title: ______________ Date: ______________	UTAH DIVISION OF PUBLIC UTILITIES By: ______________ Title: ______________ Date: ______________

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS By: ________ Title: ________ Date: ________	PACKAGING CORPORATION OF AMERICA By: ________ Title: ________ Date: ________
POWDER RIVER BASIN RESOURCE COUNCIL By: ________ Title: ________ Date: ________	RENEWABLE NORTHWEST By: ________ Title: ________ Date: ________
SIERRA CLUB By: ________ Title: ________ Date: ________	UTAH ASSOCIATION OF ENERGY USERS By: [signature] Title: Counsel Date: 11/27/19
UTAH CLEAN ENERGY By: ________ Title: ________ Date: ________	UTAH DIVISION OF PUBLIC UTILITIES By: ________ Title: ________ Date: ________

EXECUTION VERSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS By: __________ Title: __________ Date: __________	PACKAGING CORPORATION OF AMERICA By: __________ Title: __________ Date: __________
POWDER RIVER BASIN RESOURCE COUNCIL By: __________ Title: __________ Date: __________	RENEWABLE NORTHWEST By: __________ Title: __________ Date: __________
SIERRA CLUB By: __________ Title: __________ Date: __________	UTAH ASSOCIATION OF ENERGY USERS By: __________ Title: __________ Date: __________
UTAH CLEAN ENERGY By: __________ Title: Staff Attorney Date: 11/27/19	UTAH DIVISION OF PUBLIC UTILITIES By: __________ Title: __________ Date: __________

EXECUTION VERSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS By: __________ Title: __________ Date: __________	PACKAGING CORPORATION OF AMERICA By: __________ Title: __________ Date: __________
POWDER RIVER BASIN RESOURCE COUNCIL By: __________ Title: __________ Date: __________	RENEWABLE NORTHWEST By: __________ Title: __________ Date: __________
SIERRA CLUB By: __________ Title: __________ Date: __________	UTAH ASSOCIATION OF ENERGY USERS By: __________ Title: __________ Date: __________
UTAH CLEAN ENERGY By: __________ Title: __________ Date: __________	UTAH DIVISION OF PUBLIC UTILITIES By: [signature] Title: DIRECTOR Date: 11/25/19

EXECUTION VERSION

UTAH INDUSTRIAL ENERGY CONSUMERS By: __________ Title: __________ Date: __________	UTAH OFFICE OF CONSUMER SERVICES By: Michele Beck Title: Director Date: 11-27-19
VOTE SOLAR By: __________ Title: __________ Date: __________	WASHINGTON PUBLIC COUNSEL By: __________ Title: __________ Date: __________
WASHINGTON UTILITIES & TRANSPORTATION COMMISSION STAFF By: __________ Title: __________ Date: __________	WESTERN RESOURCE ADVOCATES By: __________ Title: __________ Date: __________
WOLVERINE FUELS By: __________ Title: __________ Date: __________	WYOMING INDUSTRIAL ENERGY CONSUMERS By: __________ Title: __________ Date: __________

UTAH INDUSTRIAL ENERGY CONSUMERS By: __________ Title: __________ Date: __________	UTAH OFFICE OF CONSUMER SERVICES By: __________ Title: __________ Date: __________
VOTE SOLAR By: __________ Title: __________ Date: __________	WASHINGTON PUBLIC COUNSEL By: __________ Title: __________ Date: __________
WASHINGTON UTILITIES & TRANSPORTATION COMMISSION STAFF By: __________ Title: __________ Date: __________	WESTERN RESOURCE ADVOCATES By: __________ Title: Senior Staff Attorney Date: November 27, 2019
WOLVERINE FUELS By: __________ Title: __________ Date: __________	WYOMING INDUSTRIAL ENERGY CONSUMERS By: __________ Title: __________ Date: __________

UTAH INDUSTRIAL ENERGY CONSUMERS By: __________ Title: __________ Date: __________	UTAH OFFICE OF CONSUMER SERVICES By: __________ Title: __________ Date: __________
VOTE SOLAR By: __________ Title: __________ Date: __________	WASHINGTON PUBLIC COUNSEL By: __________ Title: __________ Date: __________
WASHINGTON UTILITIES & TRANSPORTATION COMMISSION STAFF By: __________ Title: __________ Date: __________	WESTERN RESOURCE ADVOCATES By: __________ Title: __________ Date: __________
WOLVERINE FUELS By: [signature] Title: Chief Administrative Officer Date: 11/26/19	WYOMING INDUSTRIAL ENERGY CONSUMERS By: __________ Title: __________ Date: __________

UTAH INDUSTRIAL ENERGY CONSUMERS By: __________ Title: __________ Date: __________	UTAH OFFICE OF CONSUMER SERVICES By: __________ Title: __________ Date: __________
VOTE SOLAR By: __________ Title: __________ Date: __________	WASHINGTON PUBLIC COUNSEL By: __________ Title: __________ Date: __________
WASHINGTON UTILITIES & TRANSPORTATION COMMISSION STAFF By: __________ Title: __________ Date: __________	WESTERN RESOURCE ADVOCATES By: __________ Title: __________ Date: __________
WOLVERINE FUELS By: __________ Title: __________ Date: __________	WYOMING INDUSTRIAL ENERGY CONSUMERS By: Nichols S Stafford Title: Attorney for WIEC Date: November 25, 2019

EXECUTION VERSION

WYOMING OFFICE OF CONSUMER ADVOCATE By: Ivan H. Williams Title: Senior Counsel Date: 11/25/2019	WYOMING PUBLIC SERVICE COMMISSION STAFF By: [illegible] Title: Staff Attorney Date: 11·25·2019
____________ By: ____________ Title: ____________ Date: ____________	____________ By: ____________ Title: ____________ Date: ____________
____________ By: ____________ Title: ____________ Date: ____________	____________ By: ____________ Title: ____________ Date: ____________
____________ By: ____________ Title: ____________ Date: ____________	____________ By: ____________ Title: ____________ Date: ____________

APPENDIX A

Definitions

For purposes of this Agreement, the following terms will have the following meanings:

- **"2017 Protocol"** refers to the 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol.
- **"2020 Protocol"** refers to the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol.
- **"Administrative and General Costs"** means costs included in FERC accounts 920 through 935.
- **"Assigned Production Factor" or "AP"** means States' assigned share of a Resource (see Appendix C for more details).
- **"Assigned Production - Operations and Maintenance Factor" or "APOM Factor"** means the State allocated share of all generation related operating and maintenance expenses that cannot be associated with a specific Resource, such as general office generation management expenses, that will be allocated to States calculated as each State's relative share of directly allocated generation operating and maintenance expenses for steam, hydro, and other generation functions (see Section 5.1.1 and Appendix C for more details).
- **"Class 1 Demand-Side Management" or "Class 1 DSM"** means dispatchable or scheduled firm DSM resources, sometimes referred to as direct load control programs.
- **"Closure"** means either PacifiCorp's termination of ownership interest in a Resource, permanent cessation of operations of a Resource, permanent cessation of receipt of energy from a Resource, or otherwise retirement of a Resource.
- **"Coincident Peak"** means the hour each month that the combined demand of all PacifiCorp retail customers is greatest, adjusted for normal weather conditions. The hour of coincident peak is calculated assuming weather normalized retail load, and as it relates to generation allocation factors, it includes adjustments for Class 1 DSM and Special Contract curtailments. In calculating the

coincident peak for the System Transmission Factor, the only adjustment will be for weather normalization.

- **"Commission"** means a utility regulatory commission in a State.
- **"Commissioner Forum"** means the meeting of Commissioners from all States, the goal of which is to provide an update from the MSP Workgroup. Such a forum is not required by the 2020 Protocol.
- **"Commission Order"** means a formal determination issued by a State Commission consistent with its authority as provided by a State's statutes or administrative rules.
- **"Company"** means PacifiCorp.
- **"Contributions in Aid of Construction" or "CIAC"** means contributions from customers to pay their share of a capital construction project above the amount their retail rates justify. CIAC is a reduction to rate base, (see Appendix C for more detail).
- **"Customer Ancillary Services"** means products or services that may be provided by a customer to the Company, such as in which the Company has the right to curtail electric service to the customer so as to lower the costs of operating the Company's system.
- **"Customer Ancillary Service Contracts"** means contracts between the Company and a retail customer pursuant to which the Company pays the customer for Customer Ancillary Services
- **"Decommissioning Costs"** means the costs of removal and environmental remediation or reclamation - net of any salvage value realized - required at the time a generation resource is physically retired.
- **"Decommissioning Studies"** means the engineering studies carried out in advance of planned coal-fueled Interim Period Resource Reassignment filings in February of 2021 and June of 2024, in order to identify the final Decommissioning Cost liabilities of Exiting States, as specifically identified in Section 4.3.1.
- **"Demand-Related"** describes capital and other fixed costs incurred by the Company in order to be prepared to meet the maximum demand imposed upon its system.

- **"Demand-Side Management Programs" or "DSM Programs"** means programs intended to reduce electricity use through activities or programs that promote electric energy efficiency or conservation, more efficient management of electric energy loads, or reductions in peak demand.
- **"Embedded Cost Differential" or "ECD"** means the sum of PacifiCorp's production costs of pre-2005 resources as defined in the 2010 Protocol, excluding west side hydro, Mid-Columbia Contracts, and Qualified Facility contracts, referred to as "all other generation resources" expressed in dollars per megawatt-hour compared to west hydro-electric resources production costs expressed in dollars per megawatt-hour with the difference multiplied by the hydro-electric resources megawatt-hours of production, and the differential between the all other generation resources dollars per megawatt-hour compared to Mid-Columbia Contracts costs dollars per megawatt-hour multiplied by the Mid-Columbia Contracts megawatt-hours.
    - **"Dynamic Embedded Cost Differential" or "Dynamic ECD"** means the ECD components are updated to the test period utilized in the filing.
    - **"Fixed Embedded Cost Differential" or "Fixed ECD"** means the ECD amount for a State is set at a point of time and not updated.
- **"Energy Imbalance Market" or "EIM"** means the multi-Balancing Authority Area (BAA) real-time market operated by the California Independent System Operator (CAISO) that balances electricity supply and demand every five minutes by choosing the least-cost resource to serve system load.
- **"Energy-Related"** means variable costs incurred by the Company in order to deliver the energy required to serve customers.
- **"Existing QF PPAs"** is defined in Section 4.4.1 of the agreement.

- **"Exit Date"** means the date, established in an Exit Order entered by a Commission, on which PacifiCorp intends to discontinue the allocation of costs and assignment of benefits of a coal-fueled Interim Period Resource to the State issuing the Exit Order.
- **"Exiting State"** means a State with a final order from a State Commission approving the exit from a coal-fueled Interim Period Resource on a date certain.
- **"Exit Order"** means an order entered by a Commission establishing an Exit Date consistent with the 2020 Protocol.
- **"Extended Day-Ahead Market" or "EDAM"** means a market currently still in development that will address ramping needs between intervals and uncertainty that can occur between the day-ahead and real-time markets.
- **"FERC"** means the Federal Energy Regulatory Commission.
- **"Five States"** means the States of California, Idaho, Oregon, Utah, and Wyoming.
- **"Fixed Costs"** means costs incurred by the Company that do not vary with the amount of energy delivered by the Company to its customers during any hour.
- **"Framework"** is defined in Section 1 of the Agreement.
- **"Framework Issue"** is defined in Section 1 of the Agreement.
- **"General Plant"** means capital investment included in FERC accounts 389 through 399.
- **"Implemented Issues"** is defined in Section 1 of the Agreement**.**
- **"Intangible Plant"** means capital investment included in FERC accounts 301 through 303.
- **"Interim Period"** is defined in Section 2 of the Agreement.
- **"Interim Period Resource"** means Resource in commercial operation, or with a contract delivery date, as applicable, during the Interim Period.
- **"Limited Realignment"** means the assignment of Interim Period Resources among PacifiCorp States that differ from assignment using the SGF Factor.

- **"Load-Based Dynamic Allocation Factor"** means an allocation factor that is calculated using States' monthly energy usage and/or States' contribution to monthly system Coincident Peak.
- **"Mid-Columbia Contracts"** means the various power sales agreements between PacifiCorp and Public Utility District No. 2 of Grant County, PacifiCorp and Douglas County Public Utility District, and PacifiCorp and Chelan County Public Utility District, specifically: the Power Sales Contract with Public Utility District No. 2 of Grant County dated May 22, 1956; the Power Sales Contract with Public Utility District No. 2 of Grant County dated June 22, 1959; the Priest Rapids Project Product Sales Contract with Public Utility District No. 2 of Grant County dated December 31, 2001; the Additional Products Sales Agreement with Public Utility District No. 2 of Grant County dated December 31, 2001; the Priest Rapids Project Reasonable Portion Power Sales Contract with Public Utility District No. 2 of Grant County dated December 31, 2001; the Power Sales Contract with Douglas County Public Utility District dated September 18, 1963; the Power Sales Contract with Chelan County Public Utility District dated November 14, 1957, and all successor contracts thereto.
- **"MSP Workgroup"** means a group of regulators, the Company, and other interested stakeholders that convenes to discuss the assignment or allocation of PacifiCorp revenues, costs, and investments among the States.
- **"Multi-State Process" or "MSP"** means the ongoing Company-led convening of Parties from all six States in which it operates to consider issues related to fair cost allocations among the States.
- **"Net Power Costs" or "NPC"** means PacifiCorp's fuel and wheeling expenses and costs and revenues associated with long-term Wholesale Contracts, Short-Term Purchases and Sales and Non-Firm Purchases and Sales.

"New QF PPA" is defined in Section 4.4.2 of the Agreement.

- **"Nodal Pricing Model" or "NPM"** means a method for pricing electricity proposed by the Company that is based on the marginal cost ($/MWh) of serving the next increment of demand at a given pricing node consistent with existing transmission constraints and the performance characteristics of resources.

- **"Nodal Pricing Model Memorandum of Understanding" or "NPM MOU"** means the agreement among the Parties on the prudence of the Company's proceeding to implement the Nodal Pricing Model that may be adopted for the calculation of net power costs (NPC) through a new inter-jurisdictional cost-allocation methodology.
- **"Non-Firm Purchases and Sales"** means transactions at wholesale that are not Wholesale Contracts or Short-Term Purchases and Sales.
- **"Open Access Transmission Tariff"** means PacifiCorp's Open Access Transmission Tariff on file with FERC.
- **"Operations and Maintenance" or "O&M"** means costs incurred by the Company to maintain its assets that are expensed as defined by FERC.
- **"Oregon Direct Access Consumer"** means Oregon retail electricity consumers that procure electricity from a supplier other than PacifiCorp under an Oregon Direct Access Program.
- **"Oregon Direct Access Program"** means Oregon laws, regulations, and orders that permit PacifiCorp's Oregon retail consumers to purchase electricity directly from a supplier other than PacifiCorp.
- **"Party" or "Parties"** means certain State Commission staff members, regulatory agencies, customers, consumer advocates, conservation organizations, and other interested parties from California, Idaho, Oregon, Utah, Washington, and Wyoming who have executed this Agreement.
- **"Portfolio Standard"** means a law or regulation that requires PacifiCorp to acquire: (a) a particular type of Resource, (b) a particular quantity of Resources, (c) Resources in a prescribed manner or (d) Resources located in a particular geographic area.

- **"Post-Interim Period Method"** means the resolution of the Framework Issues combined with the Implemented Issues and the Resolved Issues are all intended to result in the new allocation methodology for PacifiCorp's six States.
- **"Post-Interim Period Resources"** means Resources that begin commercial operation, or with a contract or delivery date, as applicable, after the end of the Interim Period.
- **"Qualifying Facility" or "QF"** means small power production or cogeneration facilities developed under the Public Utility Regulatory Policies Act of 1978 (PURPA) and related State laws and regulations.
- **"Qualifying Facility Power Purchase Agreement" or "QF PPA"** means contracts to purchase the output of a Qualifying Facility by the Company.
- **"Reassignment", "Reassign", or "Reassigned"** means assigning benefits from an Exiting State's share of a coal-fueled Interim Period Resource to those States with Commission orders to accept the cost responsibility allocation for the Exiting State's portion of the coal-fueled Resource.
- **"Resolved Issues"** is defined in Section 1 of the Agreement.
- **"Resource"** means a Company-owned generating unit, plant, mine, long-term Wholesale Contract, Short-Term Purchase and Sale, Non-firm Purchase and Sale, or QF contract.
- **"Short-Term Firm Purchases and Firm Sales"** means physical or financial contracts pursuant to which PacifiCorp purchases, sells, or exchanges firm power at wholesale and Customer Ancillary Service Contracts that are less than one year in duration.
- **"Short-Term Purchases and Sales"** means physical or financial contracts pursuant to which PacifiCorp purchases, sells, or exchanges firm power at wholesale and Customer Ancillary Service Contracts that are less than one year in duration.
- **"Special Contract"** means a contract entered into between PacifiCorp and one of its retail customers with prices, terms, and conditions different from otherwise-applicable tariff rates. Special Contracts

may provide for a value consideration to the customer to reflect attributes of Customer Ancillary Service Contracts.

- **"State"** means California, Oregon, Idaho, Utah, Washington, or Wyoming.
- **"State Resources"** means Interim Period Resources whose costs are assigned to a single jurisdiction to accommodate jurisdiction-specific policy preferences.
- **"System Energy Factor" or "SE Factor"** is defined in Appendix C.
- **"System Generation-Fixed Factor" or "SGF Factor"** is defined in Appendix C.
- **"System Gross Plant Distribution Factor" or "SGPD Factor"** is defined in Appendix C.
- **"System Net Plant-Distribution Factor" or "SNPD Factor"** is defined in Appendix C.
- **"System Overhead Factor" or "SO Factor"** is defined in Appendix C.
- **"System Resources"** means Interim Period Resources that are not State Resources and whose associated costs and revenues are allocated among all States on a dynamic basis.
- **"System Transmission Factor" or "ST Factor"** is defined in Appendix C.
- **"Trojan Decommissioning"** means costs associated with decommissioning the Trojan Plant.
- **"Trojan Decommissioning Fixed Factor" or ("TROJDF")** is defined in Appendix C.
- **"Trojan Plant"** means the now-decommissioned nuclear plant for which the Company is still recovering costs.
- **"Variable Costs"** means costs incurred by the Company that vary with the amount of energy delivered by the Company to its customers during any hour.
- **"Washington Public Utility Tax"** means a Washington tax on public service businesses, including businesses that engage in transportation, communications, and the supply of energy, natural gas, and water. The tax is in lieu of the business and occupation (B&O) tax.
- **"West Control Area Inter-jurisdictional Allocation Methodology" or "WCA"** means the allocation protocol methodology used by Washington to allocate costs consistent with its Balancing Area Authority-based principles governing the assets deemed to serve Washington.

- **"Wholesale Contracts"** means physical or financial contracts pursuant to which PacifiCorp purchases, sells, or exchanges firm power at wholesale and Customer Ancillary Service Contracts.

APPENDIX B

Allocation Factors by Account by Revenue Requirement Components

2020 Protocol - Appendix B
Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			INTERIM PERIOD	POST INTERIM PERIOD
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
Sales to Ultimate Customers				
440	Residential Sales			
		Retail Revenues Direct assigned - Jurisdiction	S	S
442	Commercial & Industrial Sales			
		Retail Revenues Direct assigned - Jurisdiction	S	S
444	Public Street & Highway Lighting			
		Retail Revenues Direct assigned - Jurisdiction	S	S
445	Other Sales to Public Authority			
		Retail Revenues Direct assigned - Jurisdiction	S	S
448	Interdepartmental			
		Retail Revenues Direct assigned - Jurisdiction	S	S
447	Sales for Resale			
		Wholesale Sales Direct assigned - Jurisdiction	S	S
		Non-Firm	SE	AP, NP
		Firm	SG	AP, NP
449	Provision for Rate Refund			
		Direct assigned - Jurisdiction	S	S
		Transmission	SG	ST
Other Electric Operating Revenues				
450	Forfeited Discounts & Interest			
		Retail Revenues Direct assigned - Jurisdiction	S	S
451	Misc Electric Revenue			
		Retail Revenues Direct assigned - Jurisdiction	S	S
		Other - Common	SO	SO
453	Water Sales			
		Retail Revenues Direct assigned - Jurisdiction	SG	AP
454	Rent of Electric Property			
		Retail Revenues Direct assigned - Jurisdiction	S	S
		Common	SG	ST
		Other - Common	SO	SO
456	Other Electric Revenue			
		Retail Revenues Direct assigned - Jurisdiction	S	S
		Wheeling Non-firm, Other	SE	ST
		Common	SO	SO
		Wheeling - Firm, Other	SG	ST
		Customer Related	CN	CN

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	INTERIM PERIOD FACTOR	POST INTERIM PERIOD FACTOR
Miscellaneous Revenues				
41160	Gain on Sale of Utility Plant - CR			
		Distribution	S	S
		Production	SG	AP
		Transmission	SG	ST
		General Office	SO	SO
41170	Loss on Sale of Utility Plant			
		Distribution	S	S
		Production	SG	AP
		Transmission	SG	ST
		General Office	SO	SO
4118	Gain from Emission Allowances			
		SO2 Emission Allowance sales	SE	AP
41181	Gain from Disposition of NOX Credits			
		NOX Emission Allowance sales	SE	AP
421	(Gain) / Loss on Sale of Utility Plant			
		Distribution	S	S
		Production	SG	AP
		Transmission	SG	ST
		General Office	SO	SO
		Customer Related	CN	CN
Miscellaneous Expenses				
4311	Interest on Customer Deposits			
		Customer Service Deposits	CN	CN
		Direct assigned - Jurisdiction	S	S
Steam Power Generation				
500, 502, 504-514	Operation Supervision & Engineering			
		Steam Plants O&M	SG	AP, APOMS
501	Fuel Related			
		Steam plants Fuel	SE	AP, APOMS
503	Steam From Other Sources			
		Steam Royalties	SE	AP, APOMS
Nuclear Power Generation				
517 - 532	Nuclear Power O&M			
		Nuclear Plants O&M	SG	AP
Hydraulic Power Generation				
535 - 545	Hydro O&M			
		Pacific Hydro O&M	SG	AP, APOMH
		East Hydro O&M	SG	AP, APOMH
Other Power Generation				
546, 548-554	Operation Super & Engineering			
		Other Production Plant	SG	AP, APOMO
547	Fuel			
		Other Fuel Expense	SE	AP, APOMO

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			INTERIM PERIOD	POST INTERIM PERIOD
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
Other Power Supply				
555	Purchased Power			
		Tracking Mechanisms	S	S
		Firm	SG	AP, NP
		Non-firm	SE	AP, NP
556	System Control & Load Dispatch			
		Other Expenses	SG	SE
557	Other Expenses			
		Direct assigned - Jurisdiction	S	S
		Other Expenses	SE	SE
		Other Expenses	SG	APOMS, APOMH, APOMO
		Cholla Transaction	SGCT	AP
TRANSMISSION EXPENSE				
560-564, 566-573	Transmission O&M			
		Transmission Plant O&M	SG	ST
565	Transmission of Electricity by Others			
		Firm Wheeling	SG	ST
		Non-Firm Wheeling	SE	ST
		GRID Management Charge	SG	SE
DISTRIBUTION EXPENSE				
580 - 598	Distribution O&M			
		Direct assigned - Jurisdiction	S	S
		Other Distribution	SNPD	SNPD
CUSTOMER ACCOUNTS EXPENSE				
901 - 905	Customer Accounts O&M			
		Direct assigned - Jurisdiction	S	S
		Total System Customer Related	CN	CN
CUSTOMER SERVICE EXPENSE				
907 - 910	Customer Service O&M			
		Direct assigned - Jurisdiction	S	S
		Total System Customer Related	CN	CN
SALES EXPENSE				
911 - 916	Sales Expense O&M			
		Direct assigned - Jurisdiction	S	S
		Total System Customer Related	CN	CN
ADMINISTRATIVE & GEN EXPENSE				
920-935	Administrative & General Expense			
		Direct assigned - Jurisdiction	S	S
		Customer Related	CN	CN
		Mine	SE	AP
		FERC Regulatory Expense	SG	ST
		General	SO	SO

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			INTERIM PERIOD	POST INTERIM PERIOD
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
DEPRECIATION EXPENSE				
403SP	Steam Depreciation			
		Steam Plants	SG	AP
403NP	Nuclear Depreciation			
		Nuclear Plant	SG	AP
403HP	Hydro Depreciation			
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
403OP	Other Production Depreciation			
		Other Production Plant	SG	AP
403TP	Transmission Depreciation			
		Transmission Plant	SG	ST
403	Distribution Depreciation Direct assigned - Jurisdiction			
		Land & Land Rights	S	S
		Structures	S	S
		Station Equipment	S	S
		Storage Battery Equipment	S	S
		Poles & Towers	S	S
		OH Conductors	S	S
		UG Conduit	S	S
		UG Conductor	S	S
		Line Trans	S	S
		Services	S	S
		Meters	S	S
		Inst Cust Prem	S	S
		Leased Property	S	S
		Street Lighting	S	S
403GP	General Depreciation			
		Distribution	S	S
		Steam Plants	SG	AP
		Mining	SE	AP
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
403MP	Mining Depreciation			
		Mining Plant	SE	AP

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			INTERIM PERIOD	POST INTERIM PERIOD
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
AMORTIZATION EXPENSE				
404GP	Amort of LT Plant - Capital Lease Gen			
		Direct assigned - Jurisdiction	S	S
		General	SO	SO
		Customer Related	CN	CN
404SP	Amort of LT Plant - Cap Lease Steam			
		Steam Production Plant	SG	AP
404IP	Amort of LT Plant - Intangible Plant			
		Distribution	S	S
		Production	SG	AP
		Transmission	SG	ST
		General	SO	SO
		Mining Plant	SE	AP
		Customer Related	CN	CN
404MP	Amort of LT Plant - Mining Plant			
		Mining Plant	SE	AP
404HP	Amortization of Other Electric Plant			
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
405	Amortization of Other Electric Plant			
		Direct assigned - Jurisdiction	S	S
406	Amortization of Plant Acquisition Adj			
		Direct assigned - Jurisdiction	S	S
		Production Plant	SG	AP
407	Amort of Prop Losses, Unrec Plant, etc.			
		Direct assigned - Jurisdiction	S	S
		Production,	SG	AP
		Transmission	SG	ST
Taxes Other Than Income				
408	Taxes Other Than Income			
		Direct assigned - Jurisdiction	S	S
		Property	GPS	GPS
		System Taxes	SO	SO
		Misc Energy	SE	AP
		Misc Production	SG	AP
DEFERRED ITC				
41140	Deferred Investment Tax Credit - Fed			
		ITC	DGU	DGUF
41141	Deferred Investment Tax Credit - Idaho			
		ITC	DGU	DGUF

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			INTERIM PERIOD	POST INTERIM PERIOD
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
Interest Expense				
427	Interest on Long-Term Debt			
		Direct assigned - Jurisdiction	S	S
		Interest Expense	SNP	SNP
428	Amortization of Debt Disc & Exp			
		Interest Expense	SNP	SNP
429	Amortization of Premium on Debt			
		Interest Expense	SNP	SNP
431	Other Interest Expense			
		Interest Expense	SNP	SNP
432	AFUDC - Borrowed			
		AFUDC	SNP	SNP
Interest & Dividends				
419	Interest & Dividends			
		Interest & Dividends	SNP	SNP
DEFERRED INCOME TAXES				
41010	Deferred Income Tax - DR			
		Direct assigned - Jurisdiction	S	S
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Property Tax related	GPS	GPS
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJDF
		Distribution	SNPD	SNPD
		Mining Plant	SE	AP
		Bad Debt	BADDEBT	BADDEBT
		Tax Depreciation	TAXDEPR	TAXDEPR

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			INTERIM PERIOD	POST INTERIM PERIOD
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
41110	Deferred Income Tax -CR			
		Direct assigned - Jurisdiction	S	S
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Property Tax related	GPS	GPS
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJDF
		Distribution	SNPD	SNPD
		Mining Plant	SE	AP
		Contributions in Aid of Construction	CIAC	CIAC
		Production, Other	SGCT	AP
		Book Depreciation	SCHMDEXP	SCHMDEXP
SCHEDULE - M ADDITIONS				
SCHMAF	Additions - Flow Through			
		Direct assigned - Jurisdiction	S	S
SCHMAP	Additions - Permanent			
		Direct assigned - Jurisdiction	S	S
		Mining related	SE	AP
		General	SO	SO
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Depreciation	SCHMDEXP	SCHMDEXP
SCHMAT	Additions - Temporary			
		Direct assigned - Jurisdiction	S	S
		Bad Debt	BADDEBT	BADDEBT
		Contributions in Aid of Construction	CIAC	CIAC
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJDF
		Non-Coal and Gas Production	SG	AP
		Mining Plant	SE	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Property Tax	GPS	GPS
		General	SO	SO
		Depreciation	SCHMDEXP	SCHMDEXP
		Distribution	SNPD	SNPD
		Production, Other	SGCT	AP

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			INTERIM PERIOD	POST INTERIM PERIOD
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
SCHEDULE - M DEDUCTIONS				
SCHMDF	Deductions - Flow Through			
		Direct Assigned - Jurisdiction	S	S
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Non-Coal and Gas Production	SG	AP
SCHMDP	Deductions - Permanent			
		Direct Assigned - Jurisdiction	S	S
		Mining Related	SE	AP
		Depreciation	SCHMDEXP	SCHMDEXP
		Miscellaneous	SNP	SNP
		General	SO	SO
SCHMDT	Deductions - Temporary			
		Direct Assigned - Jurisdiction	S	S
		Bad Debt	BADDEBT	BADDEBT
		Miscellaneous	SNP	SNP
		Non-Coal and Gas Production	SG	AP
		Mining related	SE	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Property Tax	GPS	GPS
		General	SO	SO
		Depreciation	TAXDEPR	TAXDEPR
		Distribution	SNPD	SNPD
		Customer Related	CN	CN
State Income Taxes				
40911	State Income Taxes			
40911		Income Before Taxes	CALCULATED	CALCULATED
40911		Renewable Energy Tax Credit	SG	AP
40910		FIT True-up	S	S
40910		Renewable Energy / Production Tax Credit	SG	AP
40911		PacifiCorp Minerals Inc.	SE	AP
40911		Foreign Tax Credit	SO	SO
Steam Production Plant				
310 - 316	Steam Plants			
		Steam Plants	SG	AP
Nuclear Production Plant				
320-325	Nuclear Plant			
		Nuclear Plant	SG	AP
Hydraulic Plant				
330-336	Hydro Plant			
		Pacific Hydro	SG	AP
		East Hydro	SG	AP

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			INTERIM PERIOD	POST INTERIM PERIOD
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
Other Production Plant				
340-346	Other Production Plant			
		Other Production Plant - Situs	S	S
		Other Production Plant	SG	AP
TRANSMISSION PLANT				
350-359	Transmission Plant			
		Transmission Plant	SG	ST
DISTRIBUTION PLANT				
360-373	Distribution Plant			
		Direct assigned - Jurisdiction	S	S
GENERAL PLANT				
389 - 398	General Plant			
		Distribution	S	S
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
		Production	SG	AP, SE
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Mining	SE	AP
399	Coal Mine			
		Mining Plant	SE	AP
1011346	General Gas Line Capital Leases			
		Capital Lease	SG	AP
1011390	General Capital Leases			
		Direct assigned - Jurisdiction	S	S
		General	SO	SO
		Generation	SG	AP
		Transmission	SG	ST
INTANGIBLE PLANT				
301	Organization			
		Direct assigned - Jurisdiction	S	S
302	Franchise & Consent			
		Direct assigned - Jurisdiction	S	S
		Production	SG	AP
		Transmission	SG	ST
303	Miscellaneous Intangible Plant			
		Distribution	S	S
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
		Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Mining	SE	AP
		Other	SG	SGF

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			INTERIM PERIOD	POST INTERIM PERIOD
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
303	Less Non-Utility Plant			
		Direct assigned - Jurisdiction	S	S
Rate Base Additions				
105	Plant Held For Future Use			
		Direct assigned - Jurisdiction	S	S
		Production	SG	AP
		Transmission	SG	ST
		Mining Plant	SE	AP
114	Electric Plant Acquisition Adjustments			
		Direct assigned - Jurisdiction	S	S
		Production Plant	SG	AP
		Transmission	SG	ST
115	Accum Provision for Asset Acquisition Adjustments			
		Direct assigned - Jurisdiction	S	S
		Production Plant	SG	AP
		Transmission	SG	ST
124	Weatherization			
		Direct assigned - Jurisdiction	S	S
		General	SO	SO
128	Pensions			
		General	SO	SO
182W	Weatherization			
		Direct assigned - Jurisdiction	S	S
186W	Weatherization			
		Direct assigned - Jurisdiction	S	S
151	Fuel Stock			
		Steam Production Plant	SE	AP
152	Fuel Stock - Undistributed			
		Steam Production Plant	SE	AP
25316	UAMPS Working Capital Deposit			
		Mining Plant	SE	AP
25317	DG&T Working Capital Deposit			
		Mining Plant	SE	AP
25319	Provo Working Capital Deposit			
		Mining Plant	SE	AP

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			INTERIM PERIOD	POST INTERIM PERIOD
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
154	Materials and Supplies			
		Direct assigned - Jurisdiction	S	S
		Production,	SG	AP
		Transmission	SG	ST
		Mining	SE	AP
		Production - Common	SG	AP
		General	SO	SO
		Distribution	SNPD	SNPD
		Production, Other	SG	AP
163	Stores Expense Undistributed			
		General	SO	SO
25318	Provo Working Capital Deposit			
		Provo Working Capital Deposit	SG	AP
165	Prepayments			
		Direct assigned - Jurisdiction	S	S
		Property Tax	GPS	GPS
		Production	SG	AP
		Transmission	SG	ST
		Mining	SE	AP
		General	SO	SO
182M	Misc Regulatory Assets			
		Direct assigned - Jurisdiction	S	S
		Production	SG	AP
		Transmission	SG	ST
		Mining	SE	AP
		General	SO	SO
		Production, Other	SGCT	AP
		Other	SG	SGF
186M	Misc Deferred Debits			
		Direct assigned - Jurisdiction	S	S
		Production	SG	AP
		Transmission	SG	ST
		General	SO	SO
		Mining	SE	AP
		Production - Common	SG	AP
		Other	SG	SGF
Working Capital				
CWC	Cash Working Capital			
		Direct assigned - Jurisdiction	S	S
OWC	Other Working Capital			
131		Cash	SNP	SNP
135		Working Funds	SG	AP
141		Notes Receivable	SO	SO
143		Other Accounts Receivable	SO	SO

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			INTERIM PERIOD	POST INTERIM PERIOD
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
232		Accounts Payable	SO	SO
232		Accounts Payable	SE	AP
232		Accounts Payable	SG	ST, AP, SGF
25330		Other Deferred Credits - Misc	SE	AP
230		Other Deferred Credits - Misc	SE	AP
254105		ARO Reg Liability	SE	AP
Rate Base Deductions				
235	Customer Service Deposits			
		Direct assigned - Jurisdiction	S	S
2281	Prov for Property Insurance			
		Prov for Property Insurance	SO	SO
2282	Prov for Injuries & Damages			
		Prov for Injuries & Damages	SO	SO
2283	Prov for Pensions and Benefits			
		Prov for Pensions and Benefits	SO	SO
22841	Accum Misc Oper Prov-Black Lung			
		Other Production	SG	AP
254105	FAS 143 ARO Regulatory Liability			
		ARO	S	S
		Trojan Plant	TROJD	TROJDF
230	Asset Retirement Obligation			
		Trojan Plant	TROJD	TROJDF
252	Customer Advances for Construction			
		Direct assigned - Jurisdiction	S	S
		Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
25398	S02 Emissions			
		S02 Emissions	SE	AP
25399	Other Deferred Credits			
		Direct assigned - Jurisdiction	S	S
		Production	SG	AP
		Transmission	SG	ST
		General	SO	SO
		Mining	SE	AP
254	Regulatory Liabilities			
		Insurance Provision	SO	SO

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			INTERIM PERIOD	POST INTERIM PERIOD
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
190	Accumulated Deferred Income Taxes			
		Direct assigned - Jurisdiction	S	S
		Bad Debt	BADDEBT	BADDEBT
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJDF
		Distribution	SNPD	SNPD
		Mining Plant	SE	AP
281	Accumulated Deferred Income Taxes			
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
282	Accumulated Deferred Income Taxes			
		Direct assigned - Jurisdiction	S	S
		Depreciation	DITBAL	DITBAL
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Miscellaneous	SNP	SNP
		Depreciation	TAXDEPR	TAXDEPR
		Depreciation	SCHMDEXP	SCHMDEXP
		System Gross Plant	GPS	GPS
		Contribution in Aid of Construction	CIAC	CIAC
		Mining	SE	AP
283	Accumulated Deferred Income Taxes			
		Direct assigned - Jurisdiction	S	S
		Depreciation	DITBAL	DITBAL
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJDF
		Production, Other	SGCT	AP
		Property Tax	GPS	GPS
		Mining Plant	SE	AP
255	Accumulated Investment Tax Credit			
		Direct assigned - Jurisdiction	S	S
		Investment Tax Credits	ITC84	ITC84
		Investment Tax Credits	ITC85	ITC85
		Investment Tax Credits	ITC86	ITC86
		Investment Tax Credits	ITC88	ITC88
		Investment Tax Credits	ITC89	ITC89
		Investment Tax Credits	ITC90	ITC90
		Investment Tax Credits	SG	SGF

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	INTERIM PERIOD FACTOR	POST INTERIM PERIOD FACTOR
PRODUCTION PLANT ACCUM DEPRECIATION				
108SP	Steam Prod Plant Accumulated Depr			
		Steam Plants	SG	AP
108NP	Nuclear Prod Plant Accumulated Depr			
		Nuclear Plant	SG	AP
108HP	Hydraulic Prod Plant Accum Depr			
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
108OP	Other Production Plant - Accum Depr			
		Other Production Plant	SG	AP
TRANS PLANT ACCUM DEPR				
108TP	Transmission Plant Accumulated Depr			
		Transmission Plant	SG	ST
DISTRIBUTION PLANT ACCUM DEPR				
108360 - 108373	Distribution Plant Accumulated Depr			
		Direct assigned - Jurisdiction	S	S
108D00	Unclassified Dist Plant - Acct 300			
		Direct assigned - Jurisdiction	S	S
108DS	Unclassified Dist Sub Plant - Acct 300			
		Direct assigned - Jurisdiction	S	S
108DP	Unclassified Dist Sub Plant - Acct 300			
		Direct assigned - Jurisdiction	S	S
GENERAL PLANT ACCUM DEPR				
108GP	General Plant Accumulated Depr.			
		Distribution	S	S
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
		Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General SO	SO	SO
		Mining Plant	SE	AP
108MP	Mining Plant Accumulated Depr.			
		Mining Plant	SE	AP
1081390	Accum Depr - Capital Lease			
		General	SO	SO
1081399	Accum Depr - Capital Lease			
		Direct assigned - Jurisdiction	S	S

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			INTERIM PERIOD	POST INTERIM PERIOD
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
ACCUM PROVISION FOR AMORTIZATION				
111SP	Accum Prov for Amort-Steam			
		Steam Plants	SG	AP
111GP	Accum Prov for Amort-General			
		Distribution	S	S
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
		Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General SO	SO	SO
111HP	Accum Prov for Amort-Hydro			
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
111IP	Accum Prov for Amort-Intangible Plant			
		Distribution	S	S
		Pacific Hydro	SG	AP
		Production	SG	AP
		Transmission	SG	ST
		General	SO	SO
		Mining	SE	AP
		Customer Related	CN	CN
111IP	Less Non-Utility Plant			
		Direct assigned - Jurisdiction	S	S
111390	Accum Prov Amort - Capital Leases			
		Distribution	S	S
		Production	SG	AP
		General	SO	SO

APPENDIX C

Definitions of Allocation Factors

Factors without an effective period will be used during and after the Interim Period.

i denotes count of jurisdictions. j denotes count of month in a year. N is the number of regulatory jurisdictions that the Company operates in and allocates costs to.

<u>Assigned Production Factor ("AP")</u> – Effective after Interim Period

$$AP_i = \frac{SGF_i}{\sum_{i=1}^{x} SGF_i}$$

where:

AP_i	=	**Assigned Production Factor** for jurisdiction i.
SGF_i	=	System Generation – Fixed Factor for jurisdiction i.
x	=	Number of jurisdictions that are assigned the unit.

The AP factor may be calculated by unit of Resources, group of Resources, or for specific periods of capital investments. The AP factor may change over time as allocations change due to jurisdictions accepting a larger or smaller assignment in units that lead to the change in the value of x.

For example,

1. Assuming a unit is assigned to States A, B and C out of six jurisdictions in year 1, and their SGF factors are

   SGF_A = 25%, SGF_B = 45%, and SGF_C = 15%, respectively, then

$$AP_A = \frac{25\%}{25\% + 45\% + 15\%} = 29.4\%$$

$$AP_B = \frac{45\%}{25\% + 45\% + 15\%} = 52.9\%$$

$$AP_C = \frac{15\%}{25\% + 45\% + 15\%} = 17.6\%$$

2. Assuming the unit is later assigned to States B and C only, then the AP factors will change to

$$AP_A = 0\%$$

$$AP_B = \frac{45\%}{45\% + 15\%} = 75\%$$

$$AP_C = \frac{15\%}{45\% + 15\%} = 25\%$$

3. Assuming the unit is later assigned to C only, then the AP factors will change to

$$AP_A = 0\%$$

$$AP_B = 0\%$$

$$AP_C = \frac{15\%}{15\%} = 100\%$$

Accounts using AP factor: Sales for Resale (447), Water Sales (453), Miscellaneous Revenue (41160, 41170, 4118, 41181, 421), Generation (500-555, 557), Administrative and General Expense (920-935), Depreciation Expense (403SP, 403NP, 403HP, 403OP, 403GP, 403MP) Amortization Expense (404SP, 404IP, 404HP, 404MP 406-407), Taxes Other Than Income (408), Deferred Income Tax Expense (41010, 41110), Schedule M, Income Taxes (40910, 40911), Generation Plant (310-346), General Plant (389-399), Intangible Plant (302-303), Plant Held for Future Use (105), Electric Plant Acquisition Adjustments (114-115), Fuel Stock (151-152), Materials and Supplies (154), Mining Working Capital Deposits (25316-25319), Prepayments (165), Misc. Regulatory Assets (182M), Misc. Deferred Debits (186M), Working Capital (135, 232, 25330, 230, 245105), Accum Misc Oper Prov-Black Lung (22841), Customer Advances for Construction (252), SO2 Emissions (25398), Other Deferred Credits (25399), Regulatory Liabilities ARO Regulatory Liability (254105), Accumulated Deferred Income Taxes (190, 281-283), Accumulated Depreciation (108SP, 108NP, 108HP, 108OP, 108GP, 108MP), Accumulated Provision for Amortization (111SP, 111GP, 111HP, 111IP, 111390)

Assigned Production Factor of New Resources – Effective after Interim Period
Initial values of AP factors for all new resources will be addressed as part of the Framework discussions on Resource Planning.

Assigned Production Hydro – O&M Factor ("APOMH") – Effective after Interim Period

$$APOMH_i = \frac{PPOMH_i}{\sum_{i=1}^{N} PPOMH_i}$$

where:

$APOMH_i$	=	**Assigned Production Hydro O&M Factor** for jurisdiction i.
$PPOMH_i$	=	Sum of all hydro production plant O&M costs allocated to jurisdiction i using the AP factors.
N	=	Number of jurisdictions.

The APOMH factor is used to allocate hydro generation related O&M costs that cannot be allocated to a specific hydro resource through an AP factor, calculated as each States' relative share of direct-allocated hydro generation and maintenance expenses.

Accounts using APOMH factor: Hydro (535-545, 557)

Assigned Production Other – O&M Factor ("APOMO") – Effective after Interim Period

$$APOMO_i = \frac{PPOMO_i}{\sum_{i=1}^{N} PPOMO_i}$$

where:

$APOMO_i$	=	**Assigned Production Other O&M Factor** for jurisdiction i.

$PPOMO_i$	=	Sum of all other production plant O&M costs allocated to jurisdiction i using the AP factors.
N	=	Number of jurisdictions.

The APOMO factor is used to allocate other generation related O&M costs that cannot be allocated to specific other production Resource through an AP factor, calculated as each States' relative share of directly-allocated other production generation and maintenance expenses.

Accounts using APOMO factor: Other Generation (546-554, 557)

<u>Assigned Production Steam – O&M Factor ("APOMS")</u> – Effective after Interim Period

$$APOMS_i = \frac{PPOMS_i}{\sum_{i=1}^{N} PPOMS_i}$$

where:

$APOMS_i$	=	**Assigned Production Steam O&M Factor** for jurisdiction i.
$PPOMS_i$	=	Sum of all steam production plant O&M costs allocated to jurisdiction i using the AP factors.
N	=	Number of jurisdictions.

The APOMS factor is used to allocate steam generation related O&M costs that cannot be allocated to specific steam resource through an AP factor, calculated as each States' relative share of direct-allocated steam generation and maintenance expenses.

Accounts using APOMS factor: Generation (500-514, 557)

<u>Bad Debt Expense Factor ("BADDEBT")</u>

$$BADDEBT_i = \frac{ACCT904_i}{\sum_{i=1}^{N} ACCT904_i}$$

where:

$BADDEBT_i$	=	**Bad Debt Expense Factor** for jurisdiction i.
$ACCT904i$	=	Balance in FERC Account 904 for jurisdiction i.
N	=	Number of jurisdictions.

The BADDEBT Factor is calculated by dividing the FERC account 904 Uncollectible Accounts amount for a jurisdiction by the total 904 amount for all jurisdictions. The factor allocates tax related costs for bad debt related expenses.

Accounts using BADDEBT factor: Deferred Income Tax Expense (41010), Schedule M, Accumulated Deferred Income Taxes (190)

<u>Contributions in Aid of Construction Factor ("CIAC")</u>

$$CIAC_i = \frac{CIACNA_i}{\sum_{i=1}^{N} CIACNA_i}$$

where:

$CIAC_i$	=	**Contributions in Aid of Construction Factor** for jurisdiction i.
$CIACNA_i$	=	Contributions in aid of construction – net additions for jurisdiction i.

N = Number of jurisdictions.

The CIAC Factor is calculated by dividing the contribution in aid of construction net additions for a jurisdiction by the total contribution in aid of construction net additions for all jurisdictions. The factor allocates tax related costs for contributions in aid of construction.

Accounts using CIAC factor: Deferred Income Tax Expense (41110), Schedule M, Accumulated Deferred Income Taxes (282)

Customer Number Factor ("CN")

$$CN_i = \frac{CUST_i}{\sum_{i=1}^{N} CUST_i}$$

where:

CN_i	=	**Customer Number Factor** for jurisdiction i.
$CUST_i$	=	Total electric customers for jurisdiction i.
N	=	Number of jurisdictions.

The Customer Number Factor is calculated using the ratio of number of customers for a jurisdiction to the total number of electric customers for all jurisdictions. The factor is used to allocate customer related costs.

Accounts using CN factor: Gain / Loss on Sale of Utility Plant (421), Customer Service Deposits (4311), Other Electric Revenue (456), Customer Account Expense (901-905), Customer Service Expense (907-910), Sales Expense (911-916), Administrative and General Expense (920-935), General Plant Depreciation (403GP), Amortization Intangible Plant (404IP), Deferred Income Tax Expense (41010, 41110), Schedule M, General Plant (389-398), Intangible Plant (303), Customer Advances for Construction (252), Accumulated Deferred Income Taxes (190, 282-283), General Plant Accumulated Depreciation (108GP), Accumulated Provision for Amortization (111IP)

Deferred Tax Balance Factor ("DITBAL")

$$DITBAL_i = \frac{DITBALA_i}{\sum_{i=1}^{N} DITBALA_i}$$

where:

$DITBAL_i$	=	**Deferred Tax Balance Factor** for jurisdiction i.
$DITBALA_i$	=	Deferred tax balance allocated to jurisdiction i. (Deferred tax balance is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track deferred tax expense & deferred tax balance.)
N	=	Number of jurisdictions.

The DITBAL Factor is used to allocate deferred tax balances to jurisdictions.

Accounts using DITBAL factor: Accumulated Deferred Income Taxes (282, 283)

Division Generation – Pacific Factor ("DGP")

$$DGP_i = \frac{SG^*{}_i}{\sum_{i=1}^{N} SG^*{}_i}$$

where:

DGP_i	=	**Division Generation – Pacific Factor** for jurisdiction i.
$SG^*{}_i$	=	SG_i if i is a pre-merger Pacific Power jurisdiction, otherwise 0.
SG_i	=	System Generation Factor for jurisdiction i.
N	=	Number of jurisdictions.

The DGP Factor is calculated as the ratio of the pre-merger Pacific Division's SG factor for a jurisdiction divided by the sum of the pre-merger Pacific Division's SG factors.

The DGP factor is only used in calculating the dynamic ECD

Division Generation – Utah Factor ("DGU")

$$DGU_i = \frac{SG^*{}_i}{\sum_{i=1}^{N} SG^*{}_i}$$

where:

DGU_i	=	**Division Generation – Utah Factor** for jurisdiction i.
$SG^*{}_i$	=	SG_i if i is a pre-merger Utah Power jurisdiction, otherwise 0.
SG_i	=	System Generation Factor for jurisdiction i.
N	=	Number of jurisdictions.

After the Interim Period, the factor is determined by the average of the four-year historical value from 2018 to 2021, or 2019 to 2022 if the Interim Period is extended.

The DGU Factor is calculated as the ratio of the pre-merger Utah Power jurisdiction's SG factor for a jurisdiction divided by the sum of the pre-merger Utah Power jurisdiction's SG factors.

The only accounts using DGU factor are Deferred Investment Tax Credits (41140, 41141)

Gross Plant System Factor ("GPS")

$$GPS_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i}{\sum_{i=1}^{N}(PP_i + PT_i + PD_i + PG_i + PI_i)}$$

where:

GPS_i	=	**Gross Plant System Factor** for jurisdiction i.
PP_i	=	Production plant for jurisdiction i.
PT_i	=	Transmission plant for jurisdiction i.
PD_i	=	Distribution plant for jurisdiction i.
PG_i	=	General plant for jurisdiction i.
PI_i	=	Intangible plant for jurisdiction i.
N	=	Number of jurisdictions.

The GPS Factor is used to allocate property taxes. It is calculated using the ratio of gross plant for a jurisdiction divided by the total gross plant for all jurisdictions.

The accounts using GPS factor: Taxes Other Than Income Taxes (408), Deferred Income Tax Expense (41010, 41110), Schedule M, Prepayments (165), Accumulated Deferred Income Taxes (282, 283)

Nodal Pricing Assignment of Net Power Costs ("NP")

Costs listed as allocated by NP in Appendix B are costs that will be allocated through the Nodal Pricing Model.

Accounts using NP factor: Sales for Resale (447), Purchased Power (555)

Schedule M – Depreciation Expense Factor ("SCHMDEXP")

$$SCHMD_i = \frac{DEPRC_i}{\sum_{i=1}^{N} DEPRC_i}$$

where:

$SCHMD_i$	=	**Schedule M – Depreciation Expense Factor** for jurisdiction i.
$DEPRC_i$	=	Depreciation in FERC Accounts 403.1 - 403.9 for jurisdiction i.
N	=	Number of jurisdictions.

The SCHMDEXP factor is used to allocate Schedule M items related to depreciation expense.
The accounts using SCHMDEXP factor: Deferred Income Tax Expense (41110), Schedule M, Accumulated Deferred Income Taxes (282)

System Capacity Factor ("SC")

$$SC_i = \frac{\sum_{j=1}^{12} TAP_{ij}}{\sum_{i=1}^{N} \sum_{j=1}^{12} TAP_{ij}}$$

where:

SC_i	=	**System Capacity Factor** for jurisdiction i.
TAP_{ij}	=	Weather-normalized peak load of jurisdiction i at the time of the system peak in month j. During the Interim Period, the peak load is further adjusted to exclude the peak load of Class 1 Demand Side Management programs and interruptible peak load of the special contracts as defined in the 2017 Protocol.
N	=	Number of jurisdictions.

The SC factor is calculated based on the relative capacity requirements of each State as determined based on 12 monthly Coincident Peaks that is used to calculate the System Generation and System Transmission factors

System Energy Factor ("SE")

$$SE_i = \frac{\sum_{j=1}^{12} TAE_{ij}}{\sum_{i=1}^{N} \sum_{j=1}^{12} TAE_{ij}}$$

where:

SE_i	=	**System Energy Factor** for jurisdiction i.
TAE_{ij}	=	Weather-normalized energy at input of jurisdiction i in month j.
N	=	Number of jurisdictions.

The SE factor is used to allocate energy-related costs and is calculated as the ratio of the weather-normalized energy at input for a jurisdiction divided by the total weather-normalized energy at input for all jurisdictions.

Accounts using SE factor for Interim period: Sales for Resale (447), Other Electric Revenue (456), Miscellaneous Revenue (4118, 41181), Steam Plants Fuel (501), Steam from Other Sources (503), Other Fuel Expense (547), Purchased Power (555), Transmission of Electricity by Others (565), Administrative and General Expense (920-935), Depreciation Expense (403MP), Amortization Expense (404IP, 404MP),Taxes Other Than Income (408), Deferred Income Tax Expense (41010, 41110), Schedule M, Federal Income Tax True-Up (40910), General Plant (389-399), Intangible Plant (303), Plant Held for Future Use (105), Fuel Stock (151, 152), Working Capital – Mining related (25316, 25317, 25319), Materials and Supplies (154), Prepayments – Mining related (165), Misc. Regulatory Assets – Mining Related (182M), Misc. Deferred Debits – Mining related (186M), Accounts Payable (232), Other Deferred Credits Misc. (25330, 230, 25399), ARO Regulatory Liability (254105), SO Emissions (25398), Regulatory Liabilities (254), Accumulated Deferred Income Taxes (190, 282-283), General Plant Accumulated Depreciation 108GP, Accumulated Provision for Amortization (111IP, 111MP)

Accounts using SE factor after Interim period: System Control & Load Dispatch (556), Other Expenses (557), Transmission of Electricity by Others - GRID Management Charge (565)

<u>System Generation Factor ("SG")</u> – Effective during the Interim Period

$$SG_i = 0.75 * SC_i + 0.25 * SE_i$$

where:

SG_i	=	**System Generation Factor** for jurisdiction i.
SC_i	=	System Capacity Factor for jurisdiction i.
SE_i	=	System Energy Factor for jurisdiction i.

The SG factor is used to allocate generation and transmission costs. It is calculated using a weighting of 75% of the SC factor and 25% of the SE factor for a jurisdiction.

Accounts using the SG factor: Sales for Resale (447), Provision for Rate Refund (449), Other Electric Operating Revenue (453, 454 ,456), Miscellaneous Revenue (41160, 41170, 421), Generation Expense (500, 502, 504-514, 517-532, 535-545, 546, 548-554, 555, 556, 557), Transmission Expense (560-564, 566-573, 565), Administrative and General Expense (920-935), Depreciation Expense (403SP, 403NP, 403HP, 403OP, 403TP, 403GP), Amortization Expense (404SP, 404HP, 404IP 406, 407), Taxes Other Than Income (408), Deferred Income Tax Expense, (41010, 41110), Schedule M, Renewable Energy Tax Credit (40911), Federal Income Tax True-Up (40910), Generation Plant (310-316, 320-325, 330-336, 340-346), Transmission Plant (350-359), General Plant (389-398, 1011390), Intangible Plant (302-303), Plant Held for Future Use (105), Electric Plant Acquisition Adjustments (114-115), Materials and Supplies (154), Working Capital Deposit (25318), Prepayments (165), Misc. Regulatory Assets (182M), Misc. Deferred Debits (186M), Working Capital (135, 232), Accumulated Misc. Operating Provision Other (22841), Customer Advances for Construction (252), Other Deferred Debits (25399), Accumulated Deferred Income Taxes (190, 281-283), Accumulated Investment Tax Credit (255), Accumulated Depreciation (108SP, 108HP, 108OP, 108TP, 108GP), Accumulated Provision for Amortization (111SP, 111GP, 111HP, 111IP, 111390)

System Generation Factor – Fixed ("SGF") – Effective after Interim Period

Based on actual SG allocation factors for the most recent four calendar years available prior to the end of the Interim Period. The SG_i factor is as defined above.)

$$SGF_i = \frac{\mathrm{PY1}SG_i + \mathrm{PY2}SG_i + \mathrm{PY3}SG_i + \mathrm{PY4}SG_i}{4}$$

where:

SGF_i	=	**System Generation – Fixed Factor** for jurisdiction i.
Prior Year (PY) 1 SG_i	=	PY1 System Generation Factor for jurisdiction i.
Prior Year (PY) 2 SG_i	=	PY2 System Generation Factor for jurisdiction i.
Prior Year (PY) 3 SG_i	=	PY3 System Generation Factor for jurisdiction i.
Prior Year (PY) 4 SG_i	=	PY4 System Generation Factor for jurisdiction i.

For Example: If the Interim Period ends December 31, 2023, then (PY) 1 = calendar year 2022, (PY) 2 = calendar year 2021, (PY) 3 = calendar year 2020, and (PY) 4 = calendar year 2019.

Accounts using SGF factor: Intangible Plant (303), Misc. Regulatory Assets (182M), Misc. Deferred Debits (186M), Working Capital (232), Accumulated Investment Tax Credit (255)

System Gross Plant Distribution Factor ("SGPD") – Effective after Interim Period

$$SGPD_i = \frac{GPD_i}{\sum_{i=1}^{N} GPD_i}$$

where:

$SGPD_i$	=	**System Gross Plant Distribution Factor** for jurisdiction i.
GPD_i	=	Gross plant distribution for jurisdiction i.
N	=	Number of jurisdictions.

This factor is calculated by taking the ratio of gross distribution plant for a jurisdiction by the total gross distribution plant for all jurisdictions.

There are no accounts allocated using the SGPD factor. This factor is used to calculate the SO factor after the Interim period.

System Net Plant - Distribution Factor ("SNPD")

$$SNPD_i = \frac{PD_i + ADPD_i}{\sum_{i=1}^{N}(PD_i + ADPD_i)}$$

where:

$SNPD_i$	=	**System Net Plant – Distribution Factor** for jurisdiction i.
PD_i	=	Distribution plant – for jurisdiction i.
$ADPD_i$	=	Accumulated depreciation distribution plant - for jurisdiction i.
N	=	Number of jurisdictions.

The SNPD factor is used to allocate non situs distribution costs. The factor is calculated as the ratio of net distribution plant for a jurisdiction by the total net distribution plant for all jurisdictions.

Accounts using the SNPD factor: Distribution O&M (580-598), Deferred Income Tax Expenses (41010, 41110), Schedule M, Materials and Supplies – Distribution (154), Accumulated Deferred Income Taxes (190)

<u>System Net Plant Factor ("SNP")</u>

$$SNP_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i + ADPP_i + ADPT_i + ADPD_i + ADPG_i + ADPI_i}{\sum_{i=1}^{N}(PP_i + PT_i + PD_i + PG_i + PI_i + ADPP_i + ADPT_i + ADPD_i + ADPG_i + ADPI_i)}$$

where:

SNP_i	=	**System Net Plant Factor** for jurisdiction i.
PP_i	=	Production plant for jurisdiction i.
PT_i	=	Transmission plant for jurisdiction i.
PD_i	=	Distribution plant for jurisdiction i.
PG_i	=	General plant for jurisdiction i.
PI_i	=	Intangible plant for jurisdiction i.
$ADPP_i$	=	Accumulated depreciation production plant for jurisdiction i.
$ADPT_i$	=	Accumulated depreciation transmission plant for jurisdiction i.
$ADPD_i$	=	Accumulated depreciation distribution plant for jurisdiction i.
$ADPG_i$	=	Accumulated depreciation general plant for jurisdiction i.
$ADPI_i$	=	Accumulated depreciation intangible plant for jurisdiction i.
N	=	Number of jurisdictions.

The SNP factor is used to allocate interest expense and miscellaneous deferred tax treatment. The factor is calculated by taking the ratio of the system net plant balance for a jurisdiction divided by the total system net plant balance for all jurisdictions.

Accounts using SNP factor: Interest Expense (427-429, 431, 432), Deferred Income Tax Expenses (41010, 41110), Schedule M, Working Capital – Cash (131), Accumulated Deferred Income Taxes (190, 282, 283)

<u>System Overhead Factor ("SO")</u> – Effective after Interim Period

$$SO_i = \frac{SC_i + SE_i + SGPD_i}{3}$$

where:

SO_i	=	**System Overhead Factor** for jurisdiction i.
SC_i	=	System Capacity Factor for jurisdiction i.
SE_i	=	System Energy Factor for jurisdiction i.
$SGPD_i$	=	System Gross Plant Distribution for jurisdiction i.

The SO factor is used to allocate system overhead costs. The SO factor used after the Interim period is calculated by taking the sum of the SC, SE and SGPD factor for a jurisdiction and dividing by three.

Accounts using SO factor after Interim period: Other Electric Operating Revenue (451, 454, 456), Miscellaneous Revenue (41160, 41170, 421), Administrative and General Expense (920-935), Depreciation Expense (403GP), Amortization Expense (404GP, 404IP), Deferred Income Tax Expenses (41010, 41110), Schedule M, Federal Income Tax True-Up (40910), General Plant (389-398, 1011390), Intangible Plant (303), Materials and Supplies (154), Stores Expense Undistributed (163), Prepayments (165), Misc. Regulatory Assets (182M), Misc. Deferred Debits (186M), Working Capital (141, 232), Rate Base Deduction Provisions (2281-2283), Other Deferred Credits (25399), Regulatory Liabilities (254), Accumulated Deferred Income Taxes (190, 282, 283), Accumulated Depreciation (108GP, 1081390), Accumulated Provision for Amortization (111GP, 111IP)

<u>System Overhead Factor ("SO")</u> – Effective during the Interim Period

$$SO_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - PP_{oi} - PT_{oi} - PD_{oi} - PG_{oi} - PI_{oi}}{\sum_{i=1}^{N}(PP_i + PT_i + PD_i + PG_i + PI_i - PP_{oi} - PT_{oi} - PD_{oi} - PG_{oi} - PI_{oi})}$$

where:

SO_i	=	**System Overhead Factor** for jurisdiction i.
PP_i	=	Gross production plant for jurisdiction i.
PT_i	=	Gross transmission plant for jurisdiction i.
PD_i	=	Gross distribution plant for jurisdiction i.
PG_i	=	Gross general plant for jurisdiction i.
PI_i	=	Gross intangible plant for jurisdiction i.
PP_{oi}	=	Gross production plant for jurisdiction i allocated on a SO factor.
PT_{oi}	=	Gross transmission plant for jurisdiction i allocated on a SO factor.
PD_{oi}	=	Gross distribution plant for jurisdiction i allocated on a SO factor.
PG_{oi}	=	Gross general plant for jurisdiction i allocated on a SO factor.
PI_{oi}	=	Gross intangible plant for jurisdiction i allocated on a SO factor.
N	=	Number of jurisdictions.

The SO factor is used to allocate system overhead costs. The SO factor used during the Interim period is calculated by taking the gross plant allocated to a jurisdiction, excluding the plant amounts allocated on SO, and dividing it by the total gross plant for all jurisdictions, excluding plant amounts allocated on SO, for all jurisdictions.

Accounts using SO factor during the Interim period: Other Electric Operating Revenue (451, 454, 456), Miscellaneous Revenue (41160, 41170, 421), Administrative and General Expense (920-935), Depreciation Expense (403GP), Amortization Expense (404GP, 404IP), Deferred Income Tax Expenses (41010, 41110), Schedule M, Federal Income Tax True-Up (40910), General Plant (389-398, 1011390), Intangible Plant (303), Materials and Supplies (154), Stores Expense Undistributed (163), Prepayments (165), Misc. Regulatory Assets (182M), Misc. Deferred Debits (186M), Working Capital (141, 232), Rate Base Deduction Provisions (2281-2283), Other Deferred Credits (25399), Regulatory Liabilities (254), Accumulated Deferred Income Taxes (190, 282, 283), Accumulated Depreciation (108GP, 1081390), Accumulated Provision for Amortization (111GP, 111IP)

<u>System Transmission Factor ("ST")</u> – Effective after Interim Period

$$ST_i = 75\% * SC_i + 25\% * SE_i$$

where:

ST_i	=	**System Transmission Factor** for jurisdiction i.
SC_i	=	System Capacity Factor for jurisdiction i.
SE_i	=	System Energy Factor for jurisdiction i.

The ST factor is used to allocate transmission related costs after the Interim period. It is calculated using a weighting of 75% of the SC factor and 25% of the SE factor for a jurisdiction.

Accounts using ST factor: Provision for Rate Refund (449), Operating Revenue (454), Other Electric Revenue (456), Miscellaneous Revenue (41160, 41170, 421), Transmission Expense (560-564, 566-573), Transmission of Electricity by Others (565), Administrative & General Expense (920-935), Depreciation Expense (403TP, 403GP), Amortization Expense (404IP, 407), Deferred Income Tax Expenses (41010, 41110), Schedule M, Transmission Plant (350-359), General Plant (389-398, 1011390), Intangible Plant (302, 303), Plant Held for Future Use (105), Electric Plant Acquisition Adjustments (114-115), Material and Supplies (154), Prepayments (165), Misc. Regulatory Assets (182M), Misc. Deferred Debits (186M), Working Capital (232), Customer Advances for Construction (252), Other Deferred Credits (25399), Accumulated Deferred Income Taxes (190, 281-283), Accumulated Depreciation (108TP, 108GP), Accumulated Provision for Amortization (111TP, 111GP, 111IP)

Tax Depreciation Factor (“TAXDEPR”)

$$TAXDEPR_i = \frac{TAXDEPRA_i}{\sum_{i=1}^{N} TAXDEPRA_i}$$

where:

$TAXDEPR_i$	=	**Tax Depreciation Factor** for jurisdiction i.
$TAXDEPRA_i$	=	Tax depreciation allocated to jurisdiction i. (Tax depreciation is allocated based on functional pre-merger and post-merger splits of plant using Divisional and System allocations from above. Each jurisdiction’s total allocated portion of tax depreciation is determined by its total allocated ratio of these functional pre- and post-merger splits to the total Company tax depreciation.)
N	=	Number of jurisdictions.

The TAXDEPR factor allocates depreciation related tax costs.

Accounts using TAXDEPR: Deferred Income Tax Expense (41010) Schedule M, Accumulated Deferred Income Taxes (282)

Trojan Decommissioning Factor (“TROJD”)

$$TROJD_i = \frac{ACCT22842_i}{\sum_{i=1}^{N} ACCT22842_i}$$

where:

$TROJD_i$	=	**Trojan Decommissioning Factor** for jurisdiction i.
$ACCT22842_i$	=	Allocated adjusted balance in FERC Account 228.42 (Accumulated Provision for Decommissioning Trojan) for jurisdiction i.
N	=	Number of jurisdictions.

The TROJD factor is used to allocate decommissioning related costs associated with the Trojan plant.

Accounts using TROJD: Deferred Income Tax Expenses (41010, 41110), Schedule M, FAS 143 ARO Regulatory Liability – Trojan Plant (254105), Asset Retirement Obligation – Trojan Plant (230), Accumulated Deferred Income Taxes (190, 283)

Trojan Decommissioning Fixed Factor (“TROJDF”)

Effective after Interim Period Based on actual TROJD allocation factors for the most recent four calendar years available prior to the end of the Interim Period. (The $TROJD_i$ factor is as defined above.)

$$TROJDF_i = \frac{\text{PY1}TROJD_i + \text{PY2}TROJD_i + \text{PY3}TROJD_i + \text{PY4}TROJD_i}{4}$$

where:

$TROJDF_i$	=	**Trojan Decommissioning– Fixed Factor** for jurisdiction i.
Prior Year (PY) 1 $TROJD_i$	=	PY1 Trojan Decommissioning Factor for jurisdiction i.
Prior Year (PY) 2 TROJDi	=	PY2 Trojan Decommissioning Factor for jurisdiction i.
Prior Year (PY) 3 TROJDi	=	PY3 Trojan Decommissioning Factor for jurisdiction i.
Prior Year (PY) 4 TROJDi	=	PY4 Trojan Decommissioning Factor for jurisdiction i.

For Example: If the Interim Period ends December 31, 2023, then (PY) 1 = calendar year 2022, (PY) 2 = calendar year 2021, (PY) 3 = calendar year 2020, and (PY) 4 = calendar year 2019. The TROJDF factor is used to allocate decommissioning related costs associated with the Trojan plant.

Accounts using TROJDF: Deferred Income Tax Expenses (41010, 41110), Schedule M, FAS 143 ARO Regulatory Liability – Trojan Plant (254105), Asset Retirement Obligation – Trojan Plant (230), Accumulated Deferred Income Taxes (190, 283)

APPENDIX D

Nodal Pricing Model Memorandum of Understanding

EXECUTION VERSION

PacifiCorp's Nodal Pricing Model Memorandum of Understanding

Introduction

1. PacifiCorp and the undersigned parties (Parties) enter into this Memorandum of Understanding (MOU) to acknowledge their support, as described below, of PacifiCorp's investment in the development and implementation of a Nodal Pricing Model (NPM) that may be adopted for the calculation of net-power costs (NPC).

Background

2. PacifiCorp is a multi-jurisdictional electric utility that is serving customers in California, Idaho, Oregon, Utah, Washington, and Wyoming.

3. Generally, PacifiCorp has allocated costs among those states using an inter-jurisdictional cost allocation methodology.

4. PacifiCorp's current inter-jurisdictional cost allocation methodology, the 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol (2017 Protocol), was adopted by the applicable regulatory commissions in Idaho, Oregon, Utah, and Wyoming in 2016, and set a process for developing a new inter-jurisdictional cost allocation methodology through a working group of stakeholders consisting of utility regulatory agencies, customers, and certain others potentially affected by inter-jurisdictional allocation procedures, known as the Multi-State Process Workgroup (MSP Workgroup).[1] Washington has used the West Control Area Inter-Jurisdictional Allocation

[1] PacifiCorp anticipates that California will adopt the 2017 Protocol in 2019.

Methodology for the purposes of cost allocations since 2007. California currently uses the Revised Protocol, but a decision on adoption of the 2017 Protocol is pending before the commission.

5. Discussions among the MSP Workgroup for the potential extension of the 2017 Protocol and/or a new inter-jurisdictional cost allocation methodology are being held.

6. In late-2017, PacifiCorp presented the MSP Workgroup with a proposal to track NPC through a NPM concept designed to facilitate each state's energy policies and unique resource portfolios while still seeking to maintain the benefits of system dispatch and optimization. PacifiCorp also indicated a potential for the NPM to provide increased dispatch efficiencies.

7. PacifiCorp's NPM proposal is to use a third-party day-ahead dispatch model to determine the schedules for each of its generation resources to serve state loads on a least-cost basis, while tracking costs and benefits associated with the different resource portfolios used to serve PacifiCorp's load in each state. PacifiCorp has been in discussions with the California Independent System Operator (CAISO) to provide the day-ahead dispatch model.

8. To allow for the anticipated implementation of NPM for potential ratemaking by 2023, PacifiCorp has determined that it must now invest related capital, incur related operations and maintenance expenses, and pay related ongoing grid management charges. Attached as Exhibit A to this MOU is a description of the type of work that PacifiCorp anticipates undertaking. The Parties understand that the list is preliminary and is not intended to be a complete list.

Agreement

9. As described in this MOU, the Parties affirm support for PacifiCorp's reasonable and prudent investment of related capital funds, related operations and maintenance expenses, and the related ongoing grid management charges to develop and implement an NPM. Exhibit B to this MOU is an estimate of the investments and ongoing-costs PacifiCorp anticipates it will make or incur through this effort and an explanation of the anticipated benefits, including cost-savings and compliance with state policy directives impacting resource portfolio decisions. The Parties agree that, based on the information provided by PacifiCorp, PacifiCorp's decision to invest capital funds and pay ongoing grid management charges to develop and implement an NPM is reasonable and prudent. However, the Parties do not necessarily agree that any specific investment or expenditure is reasonable or prudent and the Parties reserve all rights to audit, review, and challenge any specific investment or expenditure as unreasonable or imprudent in appropriate regulatory commission proceedings.

10. The Parties agree the associated grid management costs will be booked in Federal Energy Regulatory Commission (FERC) Account 565, which is included in PacifiCorp's NPC. NPM related costs will be allocated among the PacifiCorp states as follows[2]:

[2] References to "SG Factor" and "SE Factor" in the following table are to the System Generation Factor and the System Energy Factor, respectively, as used in the currently-applicable cost allocation protocol in each state, or any successor factors. References to "Fixed SG Factor" are to a proposed Fixed SG Factor that the Parties currently anticipate may be established as part of a future interstate cost allocation protocol.

NPM Associated Costs	Time Period	
	January 1, 2020 Through the Effective Date of a New Interjurisdictional Cost Allocation Protocol[3]	Beginning upon the Effective Date of a New Interstate Cost Allocation Protocol
CAISO Grid Management Charge	SG Factor	SE Factor
Capitalized Start-Up Costs for PacifiCorp ESM[4]	SG Factor	Fixed SG Factor
Capitalized CAISO Implementation Fee	SG Factor	Fixed SG Factor
Ongoing Operations and Maintenance Expense	SG Factor	SE Factor

Otherwise, this MOU shall not limit the positions any Party may take regarding how nodal pricing may be used to allocate costs amongst the states before any applicable state regulatory commission.

11. The Company shall use its best efforts to provide adequate training and documentation regarding the NPM such that Parties may understand, review, and audit NPM-derived NPC. The NPM, however, is based on CAISO FERC-jurisdictional market model to which PacifiCorp does not have and cannot provide access. For regulatory purposes, the Company will retain CAISO advisory schedules and documentation of any decision to materially deviate from those advisory schedules. The Company further agrees to provide training and facilitate access to the Company's forecasting model for any appropriate party for regulatory purposes.

[3] The Parties are currently negotiating towards a possible extension of the 2017 Inter-jurisdictional Allocation Methodology (subject to some possible changes), until a future interstate cost allocation protocol becomes effective, which the Parties currently expect may be January 1, 2023 or January 1, 2024.

[4] PacifiCorp's Energy Supply Management (ESM) is the business unit responsible for scheduling and dispatching PacifiCorp's generation resources to serve retail load and buy/sell in wholesale energy and capacity markets.

12. The Parties acknowledge that this MOU does not address any other aspect of the on-going negotiations regarding an extension of the 2017 Protocol or a new inter-jurisdictional cost allocation methodology. By executing this MOU, no Party is agreeing to any other issue not agreed to in this MOU.

13. This MOU may be executed in counterparts and each signed counterpart constitutes an original document.

14. The obligations of any state agency that is a party to this MOU shall be interpreted in a manner consistent with its statutory authority and responsibilities, and any explanation and support provided in this MOU or in any regulatory proceeding shall be consistent with its statutory authority and responsibility.

15. This MOU is entered into by each Party on the date entered below such Party's signature.

PACIFICORP

By: [signature]

Date: 8/26/19

WIEC
Organization

By: [signature]

Date: 8/26/2019

EXECUTION VERSION

Western Resource Advocates *Organization*	Utah Division of Pub. Utils. *Organization*
By: Sophie Hayes	By:
Date: 08-26-2019	Date: 8/26/19
Utah Association of Energy Users *Organization*	Idaho Public Utilities Comm *Organization*
By:	By: Terri Carlock
Date: 8-26-19	Date: 8/26/2019
Bayer - Monsanto *Organization*	Utah Clean Energy *Organization*
By: Randall C. Budge	By: Hunter Holt
Date: 8/26/2019	Date: 8/26/2019

EXECUTION VERSION

Oregon Public Utility Commission staff *Organization*	Powder River Basin Resource Council *Organization*
By: [signature]	By: [signature] Shannon Anderson
Date: 8/26/19	Date: 8/26/19
Wyoming Office of Consumer Advocate *Organization*	Wyoming Public Service Commission Staff *Organization*
By: [signature]	By: [signature]
Date: 08/27/2019	Date: 8-26-2019
Alliance of Western Energy Consumers *Organization*	 *Organization*
By: [signature]	By:
Date: 8/27/19	Date:

6

EXECUTION VERSION

Utah Office of Consumer Services
Organization

By: [signature]

Date: 8-27-19

Organization

By: ______________________

Date: ______________________

Organization

By: ______________________

Date: ______________________

Organization

By: ______________________

Date: ______________________

Organization

By: ______________________

Date: ______________________

Organization

By: ______________________

Date: ______________________

EXECUTION VERSION

Oregon Citizens' Utility Board
Organization

By: [signature]
MIKE GOETZ, General Counsel

Date: August 28, 2019

Organization

By: ________________

Date: ________________

Organization

By: ________________

Date: ________________

Organization

By: ________________

Date: ________________

Organization

By: ________________

Date: ________________

Organization

By: ________________

Date: ________________

EXECUTION VERSION

Washington Utilities & Transport. Commission Staff	Wolverine Fuels
Organization	*Organization*
By: [signature]	By: James [signature]
Date: August 26, 2019	Date: Sept 03, 2019
Organization	*Organization*
By: ______	By: ______
Date: ______	Date: ______
Organization	*Organization*
By: ______	By: ______
Date: ______	Date: ______

EXHIBIT A

Nodal Pricing Model Statement of Work

Introduction

PacifiCorp has requested the CAISO provide a design proposal for a NPM that can be used to clear energy supply and demand bids for the PacifiCorp Balancing Authority Areas (BAA)[1] one day ahead. The CAISO proposes to leverage its existing Day-Ahead Market (DAM) technology platform, the market full network model, and data interfaces available in the real-time Energy Imbalance Market (EIM) to provide the NPM solution. PacifiCorp is currently an EIM Entity participating in the EIM and has already developed systems and data interfaces with the EIM in submitting data and receiving settlement statements. Consequently, the proposed solution would require an expansion of PacifiCorp's bidding, scheduling, and settlement systems for the NPM, while gaining full access to the most advanced security constrained unit commitment tool currently used in the CAISO's DAM.

Nodal Pricing Model

Currently, the CAISO's DAM footprint is limited to the CAISO BAA (CISO). Although supply and demand schedules in the external BAAs are not optimized, they are modeled as fixed in the DAM to produce an accurate market and power flow solution. The CAISO, as the Reliability Coordinator, receives the demand forecast and generation schedules for the next day from EIM BAAs and external BAAs, as well as the Area-To-Area Net Schedule Interchange between BAAs.

For the NPM solution, the CAISO proposes to include in the DAM footprint the PacifiCorp BAAs, i.e. PACW and PACE, which are modeled as individual BAAs in the EIM. Using similar market features and technology optimization algorithm approaches employed in the EIM, the DAM will produce optimal unit commitment and hourly energy schedules for supply resources in PACW and PACE, subject to a power balance constraint for each of these BAAs, in addition to the power balance constraint for CISO and active transmission network constraints in CISO, PACE, and PACW. Energy transfers between PACW and PACE will be optimally scheduled, subject to applicable scheduling limits, whereas the net energy transfer to or from CISO will be fixed at zero, to prevent energy exchange between CISO and PacifiCorp that may impact the CAISO's DAM solution.

As an intended standard feature of the DAM, the CAISO will also be able to optimally schedule ancillary services to meet the corresponding requirements in PACW and PACE, by designating these BAAs as separate ancillary services regions with distinct requirements.

The ancillary services are the following:

- Regulation up and down;
- Spinning Reserve; and
- Non-Spinning Reserve

[1] PacifiCorp operates two BAAs, PacifiCorp East BAA (PACE) and PacifiCorp West BAA (PACW).

All ancillary services have a 10-minute ramping requirement, which is shared among the upward ancillary services. Both Spinning Reserves and Non-Spinning Reserves are contingency reserves, but Non-Spinning Reserve can also be provided by offline resources that can start up within 10 minutes. The upward ancillary services procurement is cascaded so that spin can meet non-spin requirements, and regulation up can meet both spin and non-spin requirements, to minimize the overall procurement cost.

Advisory Pricing

The day-ahead settlement for the NPM is advisory, i.e. not financially binding between PacifiCorp and CAISO. Day-ahead energy and ancillary service prices for PacifiCorp resources will be published in CAISO Market Results Interface for PacifiCorp, but they will not be published in Open Access Same-time Information System (OASIS) in the public domain. Similarly, the publication of Locational Marginal Prices at PACW and PACE pricing nodes (generally referred to as PNodes) will be suppressed in OASIS.

EXECUTION VERSION

EXHIBIT B

PacifiCorp's Estimated Costs of the Nodal Pricing Model

CAISO Grid Management Charge or Service Fee - $8 to 10 million per year

Capitalized PacifiCorp Start-Up Costs for Energy Supply Management and Settlement Processing - $3 to $5 million with 100% applicable to a future Extended Day-Ahead Market (EDAM)

Capitalized CAISO Implementation Fee – $1 to $2 million (based on Energy Imbalance Market, or EIM, implementation fee) one-time cost

Ongoing Operations and Maintenance Expense – $500,000 - $700,000 per year

Benefits of the Nodal Pricing Model

The NPM is being developed to allocate actual NPC as states move to unique generation portfolios. The NPM is intended to help preserve the system benefit of operating as a single system.

CAISO's existing technology platform is intended to reduce both schedule and budget risk to quickly implement the NPC allocation methodology that PacifiCorp is seeking to implement based on the NPM solution.

In addition to providing a method to allocate NPC, the NPM potentially offers the following benefits from using the CAISO market optimization tool:

- It provides more granular dispatch information resulting in anticipated operational cost savings.
- It allows PacifiCorp to leverage CAISO's independence as a third party market provider.
- It guarantees that the solution outcome is consistent with the CAISO EIM market solution since it is using the same exact tool and input data.
- It leverages the effort and money used to build and maintain a complex and granular Real-time network model that is used in the actual market run.
- It utilizes the same schedule data for internal and external resources informing the potential for unscheduled loop flows and is informative when performing congestion management and potentially enforcing physical flow transmission constraints.

Lastly, if the CAISO offers a Day-Ahead Market to external entities for optional participation, the NPM solution development would allow PacifiCorp to seamlessly participate in the CAISO EDAM, if and when PacifiCorp decides to join that market.

APPENDIX E

Coal-Fueled Interim Period Resource Depreciation Lives

Unit	In Service	2012 Depreciation Study Life		2018 Depreciation Study Life		Capacity (MW)	Physical Location
		OR	Other States	PP States (1)	RMP States		
A	B	C	D	E	F	G	H
Lives Addressed by Section 4.1.3.1							
Cholla 4	1981	2028	2042	Apr-25	Apr-25	387	Arizona
Colstrip 3	1984	2032	2046	2027	2027	74	Montana
Colstrip 4	1986	2032	2046	2027	2027	74	Montana
Craig 1	1980	2026	2034	2025	2025	82	Colorado
Craig 2	1979	2026	2034	2026	2026	82	Colorado
Lives Addressed by Sections 4.1.3.2 and 4.1.3.3							
Dave Johnston 1	1959	2023	2027	2023	2027	99	Wyoming
Dave Johnston 2	1960	2023	2027	2023	2027	106	Wyoming
Dave Johnston 3	1964	2023	2027	2023	2027	220	Wyoming
Dave Johnston 4	1972	2023	2027	2023	2027	330	Wyoming
Hunter 1	1978	2029	2042	2029	2042	418	Utah
Hunter 2	1980	2029	2042	2029	2042	269	Utah
Hunter 3	1983	2029	2042	2029	2042	471	Utah
Huntington 1	1977	2030	2036	2029	2036	459	Utah
Huntington 2	1974	2030	2036	2029	2036	450	Utah
Jim Bridger 1	1974	2025	2037	2025	2028	354	Wyoming
Jim Bridger 2	1975	2025	2037	2025	2032	359	Wyoming
Jim Bridger 3	1976	2025	2037	2025	2037	349	Wyoming
Jim Bridger 4	1979	2025	2037	2025	2037	353	Wyoming
Naughton 1	1963	2028	2029	2028	2029	156	Wyoming
Naughton 2	1968	2028	2029	2028	2029	201	Wyoming
Wyodak	1978	2026	2039	2026	2039	268	Wyoming
Lives Addressed by Section 4.1.5							
Hayden 1	1965	2023	2030	2023	2030	44	Colorado
Hayden 2	1976	2023	2030	2023	2030	33	Colorado

(1) The life of coal plants for Washington is addressed in Section 4.1.4.

APPENDIX F

Washington Inter-Jurisdictional Allocation Methodology Memorandum of Understanding

The Washington Inter-Jurisdictional Allocation Methodology Memorandum of Understanding

Introduction

PacifiCorp d/b/a Pacific Power and Light Company (PacifiCorp or Company), Staff of the Washington and Utilities and Transportation Commission (Staff), Public Counsel Unit of the Washington State Attorney General's Office (Public Counsel) and Packaging Corporation of America (PCA), have executed this agreement (the Parties or, individually, a Party) enter into this Memorandum of Understanding (Agreement) to acknowledge their support for certain adjustments to the West Control Area Inter-Jurisdictional Allocation Methodology (WCA).

Background

PacifiCorp is a multi-jurisdictional electric utility that provides services in six states (California, Idaho, Oregon, Utah, Wyoming, and Washington). Staff is participating in PacifiCorp's Multi-State Process (MSP), working towards the Company's goal of developing a common cost allocation methodology amongst these six states. Currently, Washington uses the WCA for determining which costs are eligible for recovery in rates from customers in Washington.[1]

As approved by the Washington Utilities and Transportation Commission (Commission), the WCA isolates the costs and revenues associated with assets located in the Company's west "control area" or "PacifiCorp West Balancing Authority Area" (PACW), and allocates to Washington a proportionate share of the costs and revenues based primarily on Washington's relative contribution to demand and energy requirements. The WCA includes loads, generation and transmission assets, and wholesale contracts for facilities located in California, Oregon, and Washington. It also includes transmission and generation assets located outside of California, Oregon, and Washington that are electrically located in PACW. The WCA excludes all loads and assets located within PacifiCorp's East Balancing Authority Area (PACE).

In the context of inter-jurisdictional cost allocation, the Commission will consider a resource to be *used and useful* to Washington customers[2] if the resource "provides *quantifiable direct or indirect benefits to Washington [ratepayers] commensurate with its costs.*"[3] To modify the WCA methodology, "any changes should be considered in the context of an overall review of that methodology."[4] Additionally, Parties must demonstrate that "any changes proposed more closely aligns with the allocation of costs based on causation[.]"[5] Finally, "the party advocating for the change must make a detailed a persuasive showing demonstrating that the proposed change is appropriate."[6]

---

[1] Prior to the WCA methodology being approved in Docket UE-061546, PacifiCorp proposed the Revised Protocol as its cost allocation methodology in Docket UE-050684. The Revised Protocol presented costs as an integrated six-state system. The Commission rejected the Revised Protocol because there was not sufficient evidence in the record that the methodology complied with the legal requirements in RCW 80.04.250. *See generally* UE-050684, Order 04.
[2] *See* RCW 80.04.250
[3] Docket UE-050684, Order 04 ¶ 68.
[4] Docket UE-130043, Order 05 ¶ 92–94.
[5] *Id.*
[6] *Id.*

Foundation for this Agreement

In this memorandum of understanding, the Parties agree to support certain modifications to the WCA in the Company's forthcoming rate case provided the Company can demonstrate that the modifications within this agreement provide beneficial resources to Washington customers that are *used and useful.* In particular, the Parties agree to support these modifications if PacifiCorp can demonstrate these modifications provide quantifiable direct or indirect benefits to Washington customers, and that these benefits are commensurate with their costs.[7] The Parties agree to work collaboratively with PacifiCorp as they make this demonstration. However, as the party advocating for these changes, PacifiCorp bears the legal and factual burden to sufficiently demonstrate that these modifications better align the cost allocation methodology with the principles described above in its forthcoming general rate case.

This demonstration may include the following benefits:

- A diverse generation portfolio, including an increase in high capacity renewable generation.
- Over 170 interconnections with other BAAs and transmission operators providing access to market hubs for wholesale energy transactions (*e.g.*, Mid-C, COB, Mona, Four-Corners and Palo Verde).
- Greater Energy Imbalance Market (EIM) benefits.
- Efficiencies, such as retail load characteristics and variable resource diversity, which minimize operational costs and reduce the need to build for reserves and blackstart capability for each state.
- Washington recently enacted Senate Bill 5116, the Clean Energy Transformation Act (CETA) which, among other things, requires the elimination of coal-fired resources from PacifiCorp's electric rates by December 31, 2025. PacifiCorp's proposed modification to the WCA will facilitate a reasonable path towards PacifiCorp's compliance with CETA.[8]

Based on this understanding, the Parties agree to the following:

Agreement

1. **Implementation.** This Agreement includes modifications to the WCA subject to approval by the Commission.

---

[7] The Commission has stated that one way the Company can demonstrate this is "through historical system operation or modeling of the system showing that Eastside plant costs added to Washington rates would be offset by reductions to other cost categories (e.g., power costs), such that overall costs to Washington ratepayers would be no more than without the Eastside resources." Docket UE-050684, Order 04 ¶ 69 (emphasis added).

[8] CETA also sets a policy of 100 percent clean energy by 2045. RCW 19.405.050. Additionally, CETA establishes an interim target of 100 percent greenhouse gas (GHG) neutral by 2030, and allows utilities to meet this requirement through 80 percent non-emitting energy and an alternative compliance option, including up to 20 percent unbundled renewable energy credits. RCW 19.405.040.

1.1. PacifiCorp will file a rate case that allows for rates to go into effect (after suspension) on or before January 1, 2021. This rate case will use this MOU as the basis for any proposed modifications to the WCA.

2. **Prudence.** The proposed allocation of a particular expense or investment under this Agreement is not intended to and will not prejudge, or prevent any party from taking a position on, the prudence of those costs or the extent to which any particular cost may be reflected in rates. Nothing in this Agreement is intended to abrogate the Commission's right or obligation to: (1) determine fair, just, and reasonable rates based upon applicable laws and the record established in rate proceedings conducted by the Commission; (2) consider the impact of changes in laws, regulations, or circumstances on inter-jurisdictional allocation policies and procedures when determining fair, just, and reasonable rates; or (3) establish different allocation policies and procedures for purposes of allocating costs and revenues to different customers or customer classes.

3. **Quantification and Analytical Support.** The Parties agree to work collaboratively and in good faith to agree on the quantification and analytical support necessary for the Company to meet its legal and factual burden.

3.1. This analysis should be substantially completed before the filing of the general rate case referenced in section 1.1 and with enough time to reasonably allow parties to review the analysis.

3.2. Before the general rate case referenced in section 1.1 is filed, if a Party determines that the Company's quantification and analytical support does not demonstrate that the Company can meet its legal and factual burden, Parties have the option to withdraw their support from this agreement.

3.3. After the general rate case referenced in section 1.1 is filed, if a Party determines that this agreement does not result in fair, just and reasonable rates for Washington customers, a party may withdraw from this agreement. The withdrawing Party must provide testimony in the general rate case explaining why this agreement does not result in fair, just and reasonable rates for Washington Customers.

3.4. In the event of a Party's withdrawal, the remaining Parties may continue to support this Agreement for approval in any proceeding before the Commission.

4. **System Transmission.** The Parties agree that all existing system transmission[9] costs and benefits will be allocated using the System Generation (SG) factor as specified in Attachment 1.

4.1. Rate Impacts: To mitigate the immediate overall rate impact to Washington customers in the rate case referenced in Section 1.1, Parties agree to support the framework of the following phase-in approach:

[9] Existing transmission includes any transmission asset that is in service as of December 31, 2019.

4.1.1. An incremental allocation of one-third of existing transmission costs and benefits, which are not currently allocated to Washington under the current WCA methodology, will be included in the rate case referenced in Section 1.1.

4.1.2. An incremental allocation of an additional one-third of existing transmission costs and benefits, which are not currently allocated to Washington, will be included in a separate tariff rider with a rate effective date on or before January 1, 2022.

4.1.3. An incremental allocation of an additional one-third of existing transmission costs and benefits, which are not currently allocated to Washington, will be included in a general rate case or through an amendment to the separate tariff rider set forth in Section 4.1.2 with a rate effective date on or before January 1, 2023.

4.1.3.1. The incremental allocation in 4.1.3 will exclude the costs and benefits of all transmission-voltage, radial lines connecting resources not otherwise included in Washington rates to PacifiCorp's interconnected, network transmission system. If PacifiCorp is required to include a portion of a transmission line in its interconnected, network transmission system for open access transmission service due to a subsequent generation or load interconnection, PacifiCorp may request to include such portion of the assets in a subsequent rate case.

4.1.4. The separate tariff rider described above will remain in place until the fully allocated cost of transmission costs as described in Section 4 is included in rates through a general rate case.

4.2. New Transmission. Any new transmission[10] incremental to the existing transmission described and included in Section 3, will be system-allocated using the SG factor as specified in Attachment 1.

4.2.1. Similar to the methodology outlined in 4.1.3.1, Transmission which can be demonstrated to be used primarily for the transmission of power from generation assets which are not assigned to Washington under the WCA, as modified by this Agreement, will be excluded from this and any other allocation to Washington.

4.3. Analytical Support. As a part of the analytical support in Section 4, the Company will quantify the differences between total depreciation and ADIT balances using a WCA Allocation of transmission and the system allocation above.

[10] "New" shall constitute assets used and useful for Washington customers after December 31, 2019.

5. **Non-Emitting Resources**. The Parties agree that all existing and new non-emitting resources will be dynamically allocated using the SG Factor specified in Attachment 1.

   5.1. **Assignment.** If by December 31, 2023, none of the Parties to this agreement have signed a new cost allocation methodology with the Company, then the Company agrees to engage in collaborative conversations with the Parties and other interested Washington stakeholders to explore the following:

      5.1.1. An Assignment method for new resources for the purposes of the WCA; and,

      5.1.2. A methodology to allocate fixed shares of existing non-emitting resources.

6. **Net Power Costs (NPC).** Forecasted NPC for ratemaking purposes will be consistent with Sections 1,4,5,6, and 7 of this agreement. Additionally, Washington customers will receive all direct and indirect benefits associated with their proportional system-allocated share of existing transmission, including Energy Imbalance Market benefits.

   6.1. **Actual NPC.** Actual NPC for ratemaking purposes will include only the generation resources included in Washington rates and will be calculated using a spreadsheet.

   6.2. **Qualifying Facilities.** The costs and benefits of Power Purchase Agreements for Qualifying Facilities (QF PPAs) will continue to be situs assigned to the state having jurisdiction over the QF PPA for cost responsibility, renewable energy credit assignment and resource planning.

7. **Accelerated Depreciation.** PacifiCorp and Staff agree to support a final depreciation date of December 31, 2023, for Bridger Units 1-4, Colstrip 4 and any transmission assets associated solely with the interconnection of these units to the transmission network. This date does not represent a date of estimated closure, changes in operations, or the end of the assignment to Washington of either benefits or costs associated with these plants. Public Counsel and PCA reserve the right to make a recommendation on the depreciation for Bridger Units 1-4, Colstrip, and any transmission assets associated solely with the interconnection of these units to the transmission network in PacifiCorp's forthcoming general rate case.

   7.1. **Capital Investments.** Washington will continue to be allocated a WCA share of ongoing capital investments expenses for these plants, excluding incremental capital investments that are made primarily for the purpose of extending the life of these plants. Incremental capital investments that are made primarily for the purpose of extending the life of these plants includes, but is not limited to, those associated with achieving compliance with environmental requirements or those necessitated by catastrophic failure.

   7.2. **Deadline for Removal.** Consistent with RCW 19.405.030, PacifiCorp will remove from Washington rates all costs and benefits associated with Bridger units 1-4 and Colstrip unit 4 no later than December 31, 2025.

7.3. **Resource Flexibility.** The dates articulated in this section are agreed upon by parties to facilitate the removal of coal from Washington Rates by 2025, and provide the flexibility that may allow for early compliance with CETA.

8. **Decommissioning Cost.** Washington will continue to be allocated ongoing and expected decommissioning expenses for a WCA share of Jim Bridger Units 1-4 and Colstrip Unit 4.

8.1. **Colstrip Engineering Study.** The Company will provide by March 30, 2020, an independent engineering study of estimated decommissioning costs for Colstrip.

8.2. **Jim Bridger Engineering Study.** The Company will provide by January 15, 2020, an independent engineering study of estimated decommissioning costs for Jim Bridger.

8.3. **Cost Assignment.** To facilitate the allocation of decommissioning costs, Parties agree to support a system allocation of the costs associated with an independent engineering study in 8.1 and 8.2.

9. This agreement proposes modifications to the WCA, which serves as the basis for allocating costs in Washington. PacifiCorp will allocate costs based on the WCA consistent with the modifications in this Agreement for ratemaking purposes in Washington unless a different cost allocation method is approved by the Commission.

10. Each Party to this Agreement represents that they are signing this Agreement in good faith and that they intend to abide by the terms of this Agreement.

11. This Agreement may be executed in counterparts and each signed counterpart constitutes an original document.

12. Attachment 1 contains updated allocation factors consistent with this Agreement.

13. This Agreement is entered into by each Party on the date entered below such Party's signature.

PACIFICORP

By: ______________________________

Title: ______________________________

Date:______________________________

STAFF OF THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

By: ______________________________

Title: ______________________________

Date:______________________________

PUBLIC COUNSEL

By: ______________________________

Title: ______________________________

Date:______________________________

PACKAGING CORPORATION OF AMERICA

By: ______________________________

Title: ______________________________

Date:______________________________

PACIFICORP	**STAFF OF THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**
By:	By:
Title: VICE PRESIDENT, REGULATION	Title:
Date: November 22, 2019	Date:
PUBLIC COUNSEL	**PACKAGING CORPORATION OF AMERICA**
By:	By:
Title:	Title: Attorney
Date:	Date: 11/22/19

PACIFICORP

By: ____________________________

Title: ____________________________

Date: ____________________________

STAFF OF THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

By: Mark Vasconi

Title: Director, Regulatory Services

Date: Nov. 22, 2019

PUBLIC COUNSEL

By: ____________________________

Title: ____________________________

Date: ____________________________

PACKAGING CORPORATION OF AMERICA

By: ____________________________

Title: ____________________________

Date: ____________________________

PACIFICORP	**STAFF OF THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**
By: ______________________________	By: ______________________________
Title: ______________________________	Title: ______________________________
Date: ______________________________	Date: ______________________________
PUBLIC COUNSEL	**PACKAGING CORPORATION OF AMERICA**
By: ______________________________	By: ______________________________
Title: Assistant Attorney General	Title: ______________________________
Date: 11/21/2019	Date: ______________________________

APPENDIX G

Special Contracts

Special Contracts without Ancillary Service Contract Attributes

For allocation purposes, Special Contracts without identifiable Customer Ancillary Service attributes are viewed as one transaction.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the reduction in load will be reflected in the host jurisdiction's Load-Based Dynamic Allocation Factors.

Actual revenues received from Special Contract customer will be assigned to the State where the Special Contract customer is located.

See example in Table 1.

Special Contracts with Customer Ancillary Service Attributes

For allocation purposes, Special Contracts with Customer Ancillary Service attributes are viewed as two transactions. PacifiCorp sells the customer electricity at the retail service rate and then buys the electricity back during the interruption period at the Customer Ancillary Service Contract's rate.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the host jurisdiction's Load-Based Dynamic Allocation Factors and the retail service revenue are calculated as though the interruption did not occur.

Revenues received from Special Contract customer, before any discounts for Customer Ancillary Services attributes of the Special Contract, will be assigned to the State where the Special Contract customer is located.

Discounts from tariff prices provided for in Special Contracts that recognize the Customer Ancillary Services attributes of the Contract, and payments to retail customers for Customer Ancillary Services will be allocated among States on the same basis as System Resources.

See example in Table 2.

Buy-through of Economic Curtailment

When a buy-through option is provided with economic curtailment, the load, costs, and revenue associated with a customer buying through economic curtailment will be excluded from the calculation of State revenue requirements. The cost associated with the buy-through will be removed from the calculation of net power costs, the Special Contract customer load associated with the buy-through will be not be included in the calculation of Load-Based Dynamic Allocation Factors, and the revenue associated with the buy-through will not be included in State revenues.

Table 1
Interruptible Contract Without Ancillary Service Contract Attributes
Effect on Revenue Requirement

		Factor	Total system	Jurisdiction 1	Jurisdiction 2	Jurisdiction 3
1	**Loads**					
2	Jurisdictional Loads - No Interruptible Service					
3	Jurisdictional Sum of 12 monthly CP demand (MW)		72,000	24,000	36,000	12,000
4	Jurisdictional Annual Energy (MWh)		42,000,000	14,000,000	21,000,000	7,000,000
5						
6	Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7	Jurisdictional Sum of 12 monthly CP demand (MW)		71,700	24,000	35,700	12,000
8	Jurisdictional Annual Energy (MWh)		41,962,500	14,000,000	20,962,500	7,000,000
9						
10	Special Contract Customer Revenue and Load - Non Interruptible Service					
11	Special Contract Customer Revenue		$ 20,000,000		$ 20,000,000	
12	Special Contract Customer Sum of 12 CPs (MW) (Included in line 2)		900	-	900	-
13	Special Contract Annual Energy (MWh) (Included in line 3)		500,000	-	500,000	-
14						
15	Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16	Special Contract Customer Revenue		$ 16,000,000		$ 16,000,000	
17	Discount for Ancillary Services				-	
18	Net Cost to Special Contract Customer		$ 16,000,000		$ 16,000,000	
19	Special Contract Sum of 12 CP- Reflecting Actual Interruptions (MW) (Included in line 7)		600	-	600	-
20	Special Contract Annual Energy- Reflecting Actual Interruptions (MWh) (Included in line 8)		462,500	-	462,500	-
21						
22	System Cost Savings from Interruption		$4,000,000			
23						
24	**Allocation Factors**					
25	No Interruptible Service					
26	SE factor (Calculated from line 4)	SE1	100.00%	33.33%	50.00%	16.67%
27	SC factor (Calculated from line 3)	SC1	100.00%	33.33%	50.00%	16.67%
28	SG factor (line 27*75% + line 26*25%)	SG1	100.00%	33.33%	50.00%	16.67%
29						
30	With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE factor (Calculated from line 8)	SE2	100.00%	33.36%	49.96%	16.68%
32	SC factor (Calculated from line 7)	SC2	100.00%	33.47%	49.79%	16.74%
33	SG factor (line 32*75% + line 31*25%)	SG2	100.00%	33.45%	49.83%	16.72%
34						
35						
36			**No Interruptible Service**			
37						
38	**Cost of Service**					
39	Energy Cost	SE1	$ 500,000,000	$ 166,666,667	$ 250,000,000	$ 83,333,333
40	Demand Related Costs	SG1	$ 1,000,000,000	$ 333,333,333	$ 500,000,000	$ 166,666,667
41	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
42						
43	**Revenues**					
44	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
45	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**
46						
47						
48			**With Interruptible Service**			
49						
50	**Cost of Service**					
51	Energy Cost	SE2	$ 498,000,000	$ 166,148,347	$ 248,777,480	$ 83,074,173
52	Demand Related Costs	SG2	$ 998,000,000	$ 334,058,577	$ 496,912,134	$ 167,029,289
53	Sum of Cost		$ 1,496,000,000	$ 500,206,924	$ 745,689,614	$ 250,103,462
54						
55	**Revenues**					
56	Special Contract Revenue	Situs	$ 16,000,000		$ 16,000,000	
57	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,206,924**	**$ 729,689,614**	**$ 250,103,462**

Table 2
Interruptible Contract With Ancillary Service Contract Attributes
Effect on Revenue Requirement

		Factor	Total system	Jurisdiction 1	Jurisdiction 2	Jurisdiction 3
1	Loads					
2	Jurisdictional Loads - No Interruptible Service					
3	Jurisdictional Sum of 12 monthly CP demand (MW)		72,000	24,000	36,000	12,000
4	Jurisdictional Annual Energy (MWh)		42,000,000	14,000,000	21,000,000	7,000,000
5						
6	Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7	Jurisdictional Sum of 12 monthly CP demand (MW)		71,700	24,000	35,700	12,000
8	Jurisdictional Annual Energy (MWh)		41,962,500	14,000,000	20,962,500	7,000,000
9						
10	Special Contract Customer Revenue and Load - Non Interruptible Service					
11	Special Contract Customer Revenue		$ 20,000,000		$ 20,000,000	
12	Special Contract Customer Sum of 12 CPs (MW) (Included in line 2)		900	-	900	-
13	Special Contract Annual Energy (MWh) (Included in line 3)		500,000	-	500,000	-
14						
15	Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16	Tariff Equivalent Revenue		$ 20,000,000		$ 20,000,000	
17	Ancillary Service Discount for 75 MW X 500 Hours of Economic Curtailment				$ (4,000,000)	
18	Net Cost to Special Contract Customer		$ 16,000,000		$ 16,000,000	
19	Special Contract Sum of 12 CP- Reflecting Actual Interruptions (MW) (Included in line 7)		600	-	600	-
20	Special Contract Annual Energy- Reflecting Actual Interruptions (MWh) (Included in line 8)		462,500	-	462,500	-
21						
22	System Cost Savings from Interruption		$4,000,000			
23						
24	Allocation Factors					
25	No Interruptible Service					
26	SE factor (Calculated from line 4)	SE1	100.00%	33.33%	50.00%	16.67%
27	SC factor (Calculated from line 3)	SC1	100.00%	33.33%	50.00%	16.67%
28	SG factor (line 27*75% + line 26*25%)	SG1	100.00%	33.33%	50.00%	16 67%
29						
30	With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE factor (Calculated from line 8)	SE2	100.00%	33.36%	49.96%	16.68%
32	SC factor (Calculated from line 7)	SC2	100.00%	33.47%	49.79%	16.74%
33	SG factor (line 32*75% + line 31*25%)	SG2	100.00%	33.45%	49.83%	16.72%
34						
35						
36	**No Interruptible Service**					
37						
38	Cost of Service					
39	Energy Cost	SE1	$ 500,000,000	$ 166,666,667	$ 250,000,000	$ 83,333,333
40	Demand Related Costs	SG1	$ 1,000,000,000	$ 333,333,333	$ 500,000,000	$ 166,666,667
41	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
42						
43	Revenues					
44	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
45	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**
46						
47						
48	**With Interruptible Service & Ancillary Service Contract**					
49						
50	Cost of Service					
51	Energy Cost	SE1	$ 498,000,000	$ 166,000,000	$ 249,000,000	$ 83,000,000
52	Demand Related Costs	SG1	$ 998,000,000	$ 332,666,667	$ 499,000,000	$ 166,333,333
53	Ancillary Service Contract - Economic Curtailment (Demand)	SG1	$ 2,000,000	$ 666,667	$ 1,000,000	$ 333,333
54	Ancillary Service Contract - Economic Curtailment (Energy)	SE1	$ 2,000,000	$ 666,667	$ 1,000,000	$ 333,333
55	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
56						
57	Revenues					
58	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
59	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**

Test Year 2021	12Mo Avg FTE[2]	Base Wages and Salaries	Overtime	AIP[4]	Bonuses[3]	Total [2]
Officers (NEO)[1]	n/a	n/a	n/a	n/a	n/a	n/a
Exempt	1,822	$ 203,848,614	$ 1,396,255	30,371,052	$ 4,478,959	$ 240,094,881
Non-Exempt/Non-Union	350	20,302,800	1,090,313	-	80,896	$ 21,474,009
Union	2,816	239,912,359	81,796,192	-	563,405	$ 322,271,956
Total	4,988	$ 464,063,773	$ 84,282,760	$ 30,371,052	$ 5,123,261	$ 583,840,846

(1) Officers (NEO) amounts are included in the "exempt" line amounts.
(2) Based on headcount as of 12 month ended June 2019 average.
(3) Bonus payments include estimates for retention and hiring, safety/performance awards not related to AIP and Long-term Incentive Plan (LTIP) payments.
(4) Based on the average AIP payout ratio for calendar years 2016, 2017, and 2018 as a percentage of wages.

Calendar Year 2019	12Mo Avg FTE	Base Wages and Salaries	Overtime	AIP [1]	Bonuses [2]	Total [3]
Officers (NEO)	3	$ 954,571	$ -	$ 1,115,274	$ 1,133,290	$ 3,203,135
Exempt	1,831	190,966,807	1,133,150	28,106,169	3,681,469	223,887,595
Non-Exempt/Non-Union [2]	344	18,753,481	710,254	-	128,851	19,592,586
Union	2,745	220,796,092	73,556,411	-	897,347	295,249,850
Total	4,922	$ 431,470,951	$ 75,399,815	$ 29,221,443	$ 5,840,957	$ 541,933,166

(1) Non-Exempt/Non-Union employees were not included in the annual incentive program for CY 2019.
(2) Bonus payments may include estimates for retention and hiring, safety/performance awards not related to AIP and Long-term Incentive Plan (LTIP) payments.
(3) Amounts are based on headcount as of December 31.

Calendar Year 2018	12Mo Avg FTE	Base Wages and Salaries	Overtime	AIP [1]	Bonuses [2]	Total [3]
Officers (NEO)	3	$ 1,250,080	$ -	$ 1,054,228	$ 26,509	$ 2,330,817
Exempt	1,816	183,538,498	1,523,892	23,963,094	3,906,653	212,932,137
Non-Exempt/Non-Union	343	18,172,454	1,346,158	-	123,073	19,641,685
Union	2,865	220,634,996	68,485,294	-	910,273	290,030,563
Total	5,027	$ 423,596,028	$ 71,355,344	$ 25,017,322	$ 4,966,508	$ 524,935,202

(1) Non-Exempt/Non-Union employees were not included in the annual incentive program for CY 2018.
(2) Bonus payments may include estimates for retention and hiring, safety/performance awards not related to AIP and Long-term Incentive Plan (LTIP) payments.
(3) Amounts are based on headcount as of December 31.

Calendar Year 2017	12Mo Avg FTE	Base Wages and Salaries	Overtime	AIP	Bonuses [1]	Total [2]
Officers (NEO)	3	$ 909,079	$ -	$ 1,275,000	$ 201,986	$ 2,386,065
Exempt	1,815	178,891,314	1,336,413	25,686,877	2,482,195	208,396,799
Non-Exempt/Non-Union	343	17,568,966	1,680,153	1,049,697	200,314	20,499,130
Union	2,869	215,997,468	61,955,860	-	1,533,923	279,487,251
Total	5,030	$ 413,366,827	$ 64,972,426	$ 28,011,574	$ 4,418,418	$ 510,769,245

(1) Bonus payments may include estimates for retention and hiring, safety/performance awards not related to AIP and Long-term Incentive Plan (LTIP) payments.
(2) Amounts are based on headcount as of December 31.

Calendar Year 2016	12Mo Avg FTE	Base Wages and Salaries	Overtime	AIP	Bonuses [1]	Total [2]
Officers (NEO)	4	$ 1,223,907	$ -	$ 1,117,100	$ 175,145	$ 2,516,152
Exempt	1,869	182,608,599	1,405,352	26,042,834	2,850,652	212,907,437
Non-Exempt/Non-Union	368	18,554,043	1,265,487	1,152,203	234,361	21,206,094
Union	2,883	214,204,323	56,995,019	-	1,493,620	272,692,962
Total	5,124	$ 416,590,872	$ 59,665,858	$ 28,312,137	$ 4,753,778	$ 509,322,645

(1) Bonus payments may include estimates for retention and hiring, safety/performance awards not related to AIP and Long-term Incentive Plan (LTIP) payments.
(2) Amounts are based on headcount as of December 31.

Net write-off, related revenue and uncollectible rates
CY 2015 - CY 2019

Calendar Year	Net Write-off		Related Revenue		Uncollectible Rate	
	Oregon	Total Pacificorp[2]	Oregon	Total Pacificorp[3]	Oregon	Total Pacificorp
2019[1]	N/A	N/A	N/A	N/A	N/A	N/A
2018	$ 8,631,127	$ 11,655,692	$ 1,284,977,555	$ 4,656,340,714	0.6717%	0.2503%
2017	$ 6,281,056	$ 15,424,209	$ 1,317,990,019	$ 4,851,077,383	0.4766%	0.3180%
2016	$ 3,985,042	$ 12,228,903	$ 1,268,559,437	$ 4,866,606,600	0.3141%	0.2513%
2015	$ 3,799,403	$ 10,227,550	$ 1,265,741,623	$ 4,810,600,630	0.3002%	0.2126%

Notes

(1) This data is not yet available and will be provided after the December 31, 2019 FERC Form No. 1, and Oregon Results of Operations have been filed.
(2) As taken from PacifiCorp's FERC Form No. 1, Page 320-323, Line 162, Account 904 Uncollectible Accounts.
(3) As taken from PacifiCorp's FERC Form No. 1, Page 300, Line 10, Total Sales of Electricity for retail customers.

UE 374/PacifiCorp
April 24, 2020
OPUC Data Request 272

OPUC Data Request 272

Referring to the Company's response in DRs 92,123 & 178, please provide the amount of Officer Incentives and Other Executives incentives (Officers) capitalized in Plant Costs.

Officers' Incentives Capitalized in Plant			
Calendar Year	PAC	Allocated to Oregon Jurisdiction	Allocated to Oregon Jurisdiction and included in rate base
2017	$	$	$
2018			
2019			
2020			
Total			

Response to OPUC Data Request 272

Please refer to the table below for the amount of Annual Incentive Plan (AIP) awards for PacifiCorp's Named Executive Officers (NEOs), capitalized to Account 107, Construction Work In Progress (CWIP). The company cannot specifically state the amount of NEO incentive in CWIP that was placed in service to Electric Plant for any year, or the amount allocated to Oregon. The amounts below are estimates of the NEO incentives in Electric Plant allocated to Oregon. The Company is unable to estimate the depreciated value of these amounts and therefore cannot provide the net amount included in rate base allocated to Oregon.

Calendar Year	PacifiCorp NEO, Capitalized AIP	Oregon's Allocated share[1]
2015	$ 256,415	$ 69,430
2016	$ 271,205	$ 75,137
2017	$ 410,100	$ 111,165
2018	$ 295,922	$ 80,898
2019	$ 397,773	Not available[2]
2020	Not available[3]	Not available[3]
Total	$ 1,631,415	

Notes:

1. Oregon’s Allocated share is extrapolated using an unadjusted gross electric plant in service percentage calculated as: Oregon’s gross electric plant in service balance divided by Total Company gross electric plant in service balance. Gross electric plant in service balances are sourced from the Company’s annual results of operations filing.
2. 2019 allocation will not be available until the Company’s 2019 results of operations is filed with the Public Utility Commission of Oregon (Commission).
3. 2020 allocation will not be available until the Company’s 2020 results of operations is filed with the Commission.

UE 374/PacifiCorp
August 24, 2020
OPUC Data Request 769

OPUC Data Request 769

Wage, Salary and Incentives - Please reconcile the following statement from the Company's 12/31/19 10-K: "PacifiCorp's criteria for assessing executive performance and determining compensation in any year is inherently subjective and is not based upon specific formulas or weighting of factors. PacifiCorp does not specifically use other companies as benchmarks when establishing its NEOs' compensation" [1] with the Company's assertion in testimony at PAC/4300, Lewis/10, regarding executive and non-executive compensation, that "The same survey data we use to benchmark base pay at the market average is also used to benchmark the appropriate at-risk incentive percent tied to each job at the market average."

Response to OPUC Data Request 769

Compensation for the three PacifiCorp Named Executive Officers is not included in the Company's benchmarking referenced in testimony PAC/4300, Lewis/10.

[1] https://www.sec.gov/Archives/edgar/data/71180/000108131620000003/bhe123119form10-k.htm

UE 374/PacifiCorp
August 24, 2020
OPUC Data Request 770

OPUC Data Request 770

Wage, Salary and Incentives - Please refer to the Company's 12/31/19 Form 10-K, which states "Under PacifiCorp's Annual Incentive Plan, or AIP, all NEOs, other than the Chairman and CEO, are eligible to earn an annual discretionary cash incentive award, which is determined on a subjective basis at the Chairman and CEO's sole discretion and is not based on a specific formula or cap. The Chairman and CEO considers a variety of factors in determining each NEO's annual incentive award including the NEO's performance, PacifiCorp's overall performance and each NEO's contribution to that overall performance. The Chairman and CEO evaluates performance using financial and non-financial objectives, including customer service, employee commitment, environmental respect, regulatory integrity, operational excellence and financial strength, as well as the NEO's response to issues and opportunities that arise during the year. No factor was individually material to the Chairman and CEO's determination regarding the amounts paid to each NEO under the AIP for 2019."

a. According to Company's 10-K, AIP is considered an "incentive", correct?
b. According to Company's 10-K, AIP is an "annual discretionary cash incentive award" which is "determined on a subjective basis" based on financial as well as non-financial metrics"?
c. According to Company's 10-K, "No factor was individually material to the Chairman and CEO's determination regarding the amounts paid to each NEO under the AIP for 2019." Please reconcile this statement with the Company's assertion that all incentives are based on one of the six pillars with direct customer benefits, as described in PAC/4300, Lewis/8.

Response to OPUC Data Request 770

a. Yes, the incentive portion is the at risk portion of total compensation.

b. Yes, for Named Executive Officers, that is correct.

c. The Annual Incentive Plan amount paid to each Named Executive Officer in 2019 was based on individual and overall company performance.

Also refer to the Company's response to OPUC 769.

UE 374/PacifiCorp
August 24, 2020
OPUC Data Request 771

OPUC Data Request 771

Confidential Request
Wage, Salary and Incentives - Please refer to PAC/4300, Lewis/8, which states that Customer Satisfaction Surveys comprise [redacted] of total incentive-based compensation and [redacted] of the Customer Service Category. If [redacted] of incentive-based compensation and [redacted] of the actual Customer Service Category are unrelated to Customer Service Surveys, how does Company measure customer service? What are these other metrics and what percentage/proportion of the total incentive awards do they comprise?

Confidential Response to OPUC Data Request 771

The Customer Service pillar represents [redacted] of the overall PacifiCorp scorecard for 2019. This pillar is comprised of three customer-related elements, as shown in Confidential Attachment OPUC 179-2. Each element represents approximately [redacted] of the overall PacifiCorp scorecard.

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

UE 374/PacifiCorp
August 24, 2020
OPUC Data Request 772

OPUC Data Request 772

Confidential Request - Wage, Salary and Incentives - Please refer to PAC/4300, Lewis/8, which refers to six pillars with direct customer benefits (customer service, employee commitment, environmental respect, regulatory integrity, operational excellence and financial strength). The Company states "each of the six pillars is weighted equally, comprising [redacted] of the total incentive-based compensation." Please describe how each is measured per employee? What is the exact metric used?

Response to OPUC Data Request 772

Managers are evaluated based on the performance measures listed on their scorecards. Their direct reports are measured based on their individual performance (incentive differentiator) and the manager's scorecard. Please see the calculation below for the metric used for calculations.

2019 Annual Incentive Plan Calculation

1. Employees without scorecards will be calculated based on the scorecard of their closest manager

OPUC Data Request 773

Wage, Salary and Incentives - Please provide the following information for each year 2014 through Base Year and Test Year as formatted in the table below on a total Company and Oregon basis.

a. Incentive Name
b. Who is Eligible
c. Financial Performance Measurement. Specify goals and percentage.
d. Non-Financial Performance Measurement. Specify goals and percentage.
e. Specify stock options, RSUs, etc.

Year	Incentive Name	Who is Eligible	Financial Performance Measurement (Goal as percent of total)	Non-Financial Performance Measurement (Goal as percent of total)	Stock Option/RSU	Total Incentive Amount
2014						$
2015						$
2016						$
2017						$
2018						$
2019						$
Base Year						$
Test Year						$

Response to OPUC Data Request 773

The Company objects to the terms “Financial Performance Measurement” and “Non-Financial Performance Measurement” as vague and ambiguous. Subject to and without waiving any objection, please refer to Attachment OPUC 773 for the requested information presented in a table. For purposes of responding to this data request, the Company has designated goals relating to its core principle of “financial strength” as being related to financial performance; however, the goals relating to financial strength significantly benefit customers, as discussed in the Surrebuttal Testimony of Julie Lewis at 9:20-23.

Calendar Year	Incentive Name	Who is Eligible	Financial Performance Measurement (Goal as percent of total)	Non-Financial Performance Measurement (Goal as percent of total)	Stock Option/RSU	Total Annual Incentive Plan[1] ($000)	Estimated Oregon Allocation ($000)
Test Year	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	The scorecard is not yet available.	The scorecard is not yet available.	NA	$ 28,420	$ 8,064
Base Year	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	16.70%	83.30%	NA	NA	NA
2019	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	16.70%	83.30%	NA	$ 29,221	$ 8,275
2018	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	16.70%	83.30%	NA	$ 25,017	$ 7,090
2017	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	16.70%	83.30%	NA	$ 28,012	$ 7,954
2016	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	16.70%	83.30%	NA	$ 28,312	$ 8,124
2015	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	The company did not have a scorecard.	The company did not have a scorecard.	NA	$ 29,693	$ 8,294
2014	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	The company did not have a scorecard.	The company did not have a scorecard.	NA	$ 33,234	$ 9,399

[1.] Test Year AIP is based on the average payout ratio for calendar years 2016, 2017 and 2018 as a percentage of eligible wages. Base Year information is not available as AIP is usually paid out in December.

UE 374/PacifiCorp
August 24, 2020
OPUC Data Request 774

OPUC Data Request 774

Wage, Salary and Incentives - Please provide the Oregon allocation of union increases for calendar years 2019, 2020, and 2021 as a percentage increase per year. Please clarify the percent increases used to calculate the $4.6 million Oregon allocated in Union wage increases in testimony at PAC/4400, McCoy/34.

Response to OPUC Data Request 774

Total company union base wages increased by 0.07 percent from calendar year 2018 to calendar year 2019. While union wages increased in 2019, Oregon's labor allocation percentage decreased from 2018 to 2019, and as a result, Oregon's allocation of the 2019 union base wages decreased by 0.01 percent. The Oregon allocation of pro forma union wage increases for years 2020 and 2021 are 3.71 percent and 3.49 percent, respectively.

The Company utilized the union percentage increases as shown in Confidential Exhibit PAC/3103 to calculate the pro forma union wages for the Test Year. Based on this calculation, the difference between Base Year and Test Year union base wages on a total company basis is $16.3 million. Oregon's allocation of this increase is $4.6 million. This increase equates to 2.90 percent on a compound annual growth rate basis.

OPUC Data Request 775

Wage, Salary and Incentives - Please provide the percent increases (including forecasts) for calendar years 2019, 2020 and 2021 for IBEW 125, IBEW 659 and UWUA 197.

Response to OPUC Data Request 775

For calendar years 2019 and 2020, please refer to the Company's response to OPUC Data Request 696.

For calendar year 2021, please refer to Confidential Exhibit PAC/3103 accompanying the Reply Testimony of Shelley E. McCoy.

OPUC Data Request 776

Wage, Salary and Incentives - Please explain why Company's percentage increases for represented Unions in its response to DR 242 do not match its response in DR 696 (see below illustration).

Company's Response to DR 242

Union Represented	% Increase[1]	Effective Date(s)	Estimated Annual Financial Impact[2]
IBEW 125 (OR, WA)	1.89%	01/26/17	514,899
IBEW 659 (OR, CA)	1.36%	04/26/17	429,251
UWUA 197 (OR)	0.93%	09/06/17	14,064
Total CY 2017			958,214
IBEW 125 (OR, WA)	2.33%	01/26/18	621,398
IBEW 125 (OR, WA)	0.20%	12/11/18	51,038
IBEW 659 (OR, CA)	1.37%	04/26/18	435,317
UWUA 197 (OR)	1.20%	05/26/18	18,358
Total CY 2018			1,126,111
IBEW 125 (OR, WA)	2.63%	09/11/19	24,851
IBEW 659 (OR, CA)	1.71%	04/26/19	522,295
IBEW 659 (OR, CA)	2.84%	08/11/19	609,544
UWUA 197 (OR)	1.51%	05/26/19	23,035
UWUA 197 (OR)	1.55%	09/11/19	441,568
Total CY 2019			1,621,293
IBEW 125 (OR, WA)	2.33%	01/26/20	621,324
			621,324

Company's Response to DR 696

	IBEW 125	IBEW 659	UWUA 197
Feb-17	2.00%		
May-17		2.00%	
Sep-17			2.00%
Feb-18	2.50%		
May-18		2.00%	
Jun-18			2.00%
Jan-19	2.50%		
May-19		2.50%	
Jun-19			2.50%
Jul-19		5.10%	
Aug-19	5.10%		
Sep-19			5.80%
Feb-20	2.50%		
Mar-20			
Apr-20			
May-20		2.50%	
Jun-20			2.50%

Response to OPUC Data Request 776

The information presented in the Company's response to OPUC Data Request 242 is based on the percentage increase in wages from the effective date of the increase to the end of the calendar year, as compared to the wage scale of the prior calendar year. Whereas, the response to OPUC Data Request 696 provided the average percentage increase by union and the timing of those increases.

Test Year 2021	12Mo Avg FTE[2]	Base Wages and Salaries	Overtime	AIP[4]	Bonuses[3]	Total [2]
Officers (NEO)[1]	n/a	n/a	n/a	n/a	n/a	n/a
Exempt	1,822	$ 203,848,614	$ 1,396,255	30,371,052	$ 4,478,959	$ 240,094,881
Non-Exempt/Non-Union	350	20,302,800	1,090,313	-	80,896	$ 21,474,009
Union	2,816	239,912,359	81,796,192	-	563,405	$ 322,271,956
Total	4,988	$ 464,063,773	$ 84,282,760	$ 30,371,052	$ 5,123,261	$ 583,840,846

(1) Officers (NEO) amounts are included in the "exempt" line amounts.
(2) Based on headcount as of 12 month ended June 2019 average.
(3) Bonus payments include estimates for retention and hiring, safety/performance awards not related to AIP and Long-term Incentive Plan (LTIP) payments.
(4) Based on the average AIP payout ratio for calendar years 2016, 2017, and 2018 as a percentage of wages.

Calendar Year 2019	12Mo Avg FTE	Base Wages and Salaries	Overtime	AIP [1]	Bonuses [2]	Total [3]
Officers (NEO)	3	$ 954,571	$ -	$ 1,115,274	$ 1,133,290	$ 3,203,135
Exempt	1,831	190,966,807	1,133,150	28,106,169	3,681,469	223,887,595
Non-Exempt/Non-Union [2]	344	18,753,481	710,254	-	128,851	19,592,586
Union	2,745	220,796,092	73,556,411	-	897,347	295,249,850
Total	4,922	$ 431,470,951	$ 75,399,815	$ 29,221,443	$ 5,840,957	$ 541,933,166

(1) Non-Exempt/Non-Union employees were not included in the annual incentive program for CY 2019.
(2) Bonus payments may include estimates for retention and hiring, safety/performance awards not related to AIP and Long-term Incentive Plan (LTIP) payments.
(3) Amounts are based on headcount as of December 31.

Calendar Year 2018	12Mo Avg FTE	Base Wages and Salaries	Overtime	AIP [1]	Bonuses [2]	Total [3]
Officers (NEO)	3	$ 1,250,080	$ -	$ 1,054,228	$ 26,509	$ 2,330,817
Exempt	1,816	183,538,498	1,523,892	23,963,094	3,906,653	212,932,137
Non-Exempt/Non-Union	343	18,172,454	1,346,158	-	123,073	19,641,685
Union	2,865	220,634,996	68,485,294	-	910,273	290,030,563
Total	5,027	$ 423,596,028	$ 71,355,344	$ 25,017,322	$ 4,966,508	$ 524,935,202

(1) Non-Exempt/Non-Union employees were not included in the annual incentive program for CY 2018.
(2) Bonus payments may include estimates for retention and hiring, safety/performance awards not related to AIP and Long-term Incentive Plan (LTIP) payments.
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Officers (NEO)	3	$ 909,079	$ -	$ 1,275,000	$ 201,986	$ 2,386,065
Exempt	1,815	178,891,314	1,336,413	25,686,877	2,482,195	208,396,799
Non-Exempt/Non-Union	343	17,568,966	1,680,153	1,049,697	200,314	20,499,130
Union	2,869	215,997,468	61,955,860	-	1,533,923	279,487,251
Total	5,030	$ 413,366,827	$ 64,972,426	$ 28,011,574	$ 4,418,418	$ 510,769,245

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(2) Amounts are based on headcount as of December 31.

Calendar Year 2016	12Mo Avg FTE	Base Wages and Salaries	Overtime	AIP	Bonuses [1]	Total [2]
Officers (NEO)	4	$ 1,223,907	$ -	$ 1,117,100	$ 175,145	$ 2,516,152
Exempt	1,869	182,608,599	1,405,352	26,042,834	2,850,652	212,907,437
Non-Exempt/Non-Union	368	18,554,043	1,265,487	1,152,203	234,361	21,206,094
Union	2,883	214,204,323	56,995,019	-	1,493,620	272,692,962
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(1) Bonus payments may include estimates for retention and hiring, safety/performance awards not related to AIP and Long-term Incentive Plan (LTIP) payments.
(2) Amounts are based on headcount as of December 31.

Test Year 2021	12Mo Avg FTE[2]	Salaries	Overtime	AIP[4]	Bonuses[3]	Total [2]
Officers (NEO)[1]	3	$ 995,496	$ -	$ 140,218	$ 10,750	$ 1,146,464
Exempt	1,819	$ 202,853,118	$ 1,396,255	28,279,451	$ 4,468,209	$ 236,997,034
Non-Exempt/Non-Union	350	20,302,800	1,090,313	-	80,896	$ 21,474,009
Union	2,816	239,912,359	81,796,192	-	563,405	$ 322,271,956
Total	4,988	$ 464,063,773	$ 84,282,760	$ 28,419,669	$ 5,123,261	$ 581,889,463

(1) Officers (NEO) amounts are calculated in the same manner as "Exempt" employees.
(2) Based on headcount as of 12 month ended June 2019 average.
(3) Bonus payments include estimates for retention and hiring, safety/performance awards not related to AIP and Long-term Incentive Plan (LTIP) payments.
(4) Based on the average AIP payout ratio for calendar years 2016, 2017, and 2018 as a percentage of wages.

Calendar Year 2019	12Mo Avg FTE	Salaries	Overtime	AIP [1]	Bonuses [2]	Total [3]
Officers (NEO)	3	$ 954,571	$ -	$ 1,115,274	$ 1,133,290	$ 3,203,135
Exempt	1,831	190,966,807	1,133,150	28,106,169	3,681,469	223,887,595
Non-Exempt/Non-Union [2]	344	18,753,481	710,254	-	128,851	19,592,586
Union	2,745	220,796,092	73,556,411	-	897,347	295,249,850
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Calendar Year 2018	12Mo Avg FTE	Salaries	Overtime	AIP [1]	Bonuses [2]	Total [3]
Officers (NEO)	3	$ 1,250,080	$ -	$ 1,054,228	$ 26,509	$ 2,330,817
Exempt	1,816	183,538,498	1,523,892	23,963,094	3,906,653	212,932,137
Non-Exempt/Non-Union	343	18,172,454	1,346,158	-	123,073	19,641,685
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Total	5,027	$ 423,596,028	$ 71,355,344	$ 25,017,322	$ 4,966,508	$ 524,935,202

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Union	2,883	214,204,323	56,995,019	-	1,493,620	272,692,962
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(1) Bonus payments may include estimates for retention and hiring, safety/performance awards not related to AIP and Long-term Incentive Plan (LTIP) payments.
(2) Amounts are based on headcount as of December 31.

(a)

Average number of FTE's	CY 2014	CY 2015	CY 2016	CY 2017	CY 2018	CY 2019
Officers (NEO)	4	5	4	3	3	3
Exempt	1,953	1,930	1,869	1,815	1,816	1,831
Non-Exempt/Non-Union	394	387	368	343	343	344
Union	2,940	2,916	2,883	2,869	2,865	2,745
Total	5,292	5,238	5,124	5,030	5,027	4,923

The table above provides the 12-month average of full-time equivalent employees, exlcuding any FTE for part-time employees, contractors and vendors. NEOs will not agree to reported amounts in PacifiCorp's SEC 10K, as the table above, includes the average number of individuals who may have changed reporting categories or left the company during the year.

(b)

Severance Costs	CY 2014	CY 2015	CY 2016	CY 2017	CY 2018	CY 2019
Officers (NEO)	n/a	n/a	n/a	n/a	n/a	n/a
Exempt	$ 259,412	$ 1,051,677	$ 1,252,346	$ 117,328	$ 316,119	$ 294,448
Non-Exempt/Non-Union	n/a	n/a	n/a	n/a	n/a	n/a
Union	-	-	-	-	$ 139,396	$ 156,506
Total	$ 259,412	$ 1,051,677	$ 1,252,346	$ 117,328	$ 455,515	$ 450,954

The table above provides the cost of severance made to individuals who left the company during the year ended December 31. Please note that reported severance costs reported for exempt employees also includes non-exempt and non-union employees.

(c)

Annual Incentive Payments	CY 2014	CY 2015	CY 2016	CY 2017	CY 2018	CY 2019
Officers (NEO)	$ 1,073,000	$ 1,325,000	$ 1,117,100	$ 1,275,000	$ 1,054,228	$ 1,115,274
Exempt	30,527,577	27,146,334	26,042,834	25,686,877	23,963,094	28,106,169
Non-Exempt/Non-Union	1,633,704	1,222,108	1,152,203	1,049,697	n/a	n/a
Union	n/a	n/a	n/a	n/a	n/a	n/a
Total	$ 33,234,281	$ 29,693,442	$ 28,312,137	$ 28,011,574	$ 25,017,322	$ 29,221,443

The table above provides annual incentive cost for payments made to individuals for the incentive year ended December 31. The Officers (NEO) AIP costs agrees to PacifiCorp's SEC 10K, Deferred Compensation, except for CY 2015, in which the table includes amounts for Natalie Hocken prior to her becoming BHE's general counsel and SVP on August 15, 2015, as well as Michael Dunn, who resigned as director and employee in March 2015. In addition, beginning with CY 2018, non-exempt/non-union employees were not longer included in the annual incentive program.

(d)

Annual Wages and Salaries	CY 2014	CY 2015	CY 2016	CY 2017	CY 2018	CY 2019
Officers (NEO)	$ 1,495,572	$ 1,694,424	$ 1,223,907	$ 909,079	$ 1,250,080	$ 954,571
Exempt	185,326,604	186,119,042	182,608,599	178,891,314	183,538,498	190,966,807
Non-Exempt/Non-Union	20,038,275	19,377,127	18,554,043	17,568,966	18,172,454	18,753,481
Union	214,562,246	213,741,744	214,204,323	215,997,468	220,634,996	220,796,092
Total	$ 421,422,697	$ 420,932,337	$ 416,590,872	$ 413,366,827	$ 423,596,028	$ 431,470,951

The table above provides the wages and salaries paid during each reported calendar year, based on headcount as of December 31. The Officers (NEO) reported salary agrees to PacifiCorp's SEC 10K, Deferred Compensation, except for CY 2015, in which the table includes amounts for Natalie Hocken prior to her becoming BHE's general counsel and SVP on August 15, 2015, as well as Michael Dunn, who resigned as director and employee in March 2015.

(e)

Annual Overtime Cost	CY 2014	CY 2015	CY 2016	CY 2017	CY 2018	CY 2019
Officers (NEO)	$ -	$ -	$ -	$ -	$ -	$ -
Exempt	1,406,114	1,874,517	1,405,352	1,336,413	1,523,892	1,133,150
Non-Exempt/Non-Union	1,138,566	1,149,959	1,265,487	1,680,153	1,346,158	710,254
Union	57,338,828	61,698,525	56,995,019	61,955,860	68,485,294	73,556,411
Total	$ 59,883,508	$ 64,723,001	$ 59,665,858	$ 64,972,426	$ 71,355,344	$ 75,399,815

The table above provides the cost of overtime and premium pay during each reported calendar year, based on headcount as of December 31.

(f)

Annual Payroll Tax Cost	CY 2014	CY 2015	CY 2016	CY 2017	CY 2018	CY 2019
NEO	$ 127,871	$ 144,873	$ 104,644	$ 77,726	$ 106,882	$ 81,616
Exempt	14,285,053	14,381,507	14,077,067	13,787,421	14,157,273	14,695,647
Non-Exempt/Non-Union	1,620,028	1,570,322	1,516,194	1,472,558	1,493,174	1,488,976
Union	20,800,432	21,071,181	20,746,750	21,263,430	22,117,702	22,517,966
Total	$ 36,833,384	$ 37,167,883	$ 36,444,655	$ 36,601,135	$ 37,875,031	$ 38,784,205

The table above provides estimated payroll tax costs, using an average of 7.65% employer tax rate (includes 6.2% Social Security tax and 1.45% Medicare tax). In addition, the NEO's calculated estimated rate includes an additional 0.9% for salaries exceeding the $200k Medicare threshold.

Union Represented	% Increase[1]	Effective Date(s)	Estimated Annual Financial Impact[2]
IBEW 57 Combustion Turbine (UT)	1.87%	01/26/17	59,745
IBEW 57 Laramie (WY)	1.03%	06/26/17	5,682
IBEW 57 Power Delivery (UT, ID & WY)	1.83%	01/26/17	1,459,183
IBEW 57 Power Supply (UT, ID & WY)	1.86%	01/26/17	684,299
IBEW 125 (OR, WA)	1.89%	01/26/17	514,899
IBEW 659 (OR, CA)	1.36%	04/26/17	429,251
UWUA 127 (WY)	0.53%	09/26/17	247,484
UWUA 197 (OR)	0.93%	09/06/17	14,064
Total CY 2017			3,414,607
IBEW 57 Combustion Turbine (UT)	1.86%	01/26/18	59,125
IBEW 57 Laramie (WY)	1.04%	06/26/18	5,854
IBEW 57 Power Delivery (UT, ID & WY)	1.83%	01/26/18	1,491,243
IBEW 57 Power Supply (UT, ID & WY)	1.86%	01/26/18	694,211
IBEW 77 (WA)	2.10%	01/26/18	24,084
IBEW 125 (OR, WA)	2.33%	01/26/18	621,398
IBEW 125 (OR, WA)	0.20%	12/11/18	51,038
IBEW 659 (OR, CA)	1.37%	04/26/18	435,317
UWUA 127 (WY)	0.71%	09/26/18	324,013
UWUA 197 (OR)	1.20%	05/26/18	18,358
Total CY 2018			3,724,641
IBEW 57 Combustion Turbine (UT)	2.33%	01/26/19	71,496
IBEW 57 Laramie (WY)	1.29%	06/26/19	9,461
IBEW 57 Power Delivery (UT, ID & WY)	2.29%	01/26/19	1,878,830
IBEW 57 Power Supply (UT, ID & WY)	2.33%	01/26/19	860,494
IBEW 77 (WA)	2.09%	01/26/19	22,593
IBEW 125 (OR, WA)	2.63%	09/11/19	24,851
IBEW 659 (OR, CA)	1.71%	04/26/19	522,295
IBEW 659 (OR, CA)	2.84%	08/11/19	609,544
UWUA 127 (WY)	0.60%	09/26/19	283,860
UWUA 197 (OR)	1.51%	05/26/19	23,035
UWUA 197 (OR)	1.55%	09/11/19	441,568
Total CY 2019			4,748,027
IBEW 57 Combustion Turbine (UT)	3.25%	01/26/20	105,525
IBEW 57 Power Delivery (UT, ID & WY)	2.76%	01/26/20	2,311,597
IBEW 57 Power Supply (UT, ID & WY)	2.90%	01/26/20	1,084,414
IBEW 77 (WA)	2.33%	01/26/20	26,781
IBEW 125 (OR, WA)	2.33%	01/26/20	621,324
			4,149,641

(1) This percentage increase represents the increase in wages from the effective date of the increase to the end of the calendar year as compared to the wage scale of the prior calendar year.

(2) The estimated annual impact is based on the time period from the effective date of the increase to the end of the calendar year. Some amounts may be reimbursed by joint owners.

PacifiCorp
Oregon General Rate Case - December 2021
Union Wage Increases
For the years 2017, 2018, 2019, and projected 2020
Attach OPUC 696

Increases occur on the 26th of each month. For this exhibit, each increase is listed on the first day of the following month. For example, an increase that occurs on December 26, 2018 is shown as effective on January 1, 20

12 Months Ended December 2017

Group Code	Labor Group	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
3	IBEW 125		2.00%										
4	IBEW 659					2.00%							
5	UWUA 197									2.00%			
8	UWUA 127										2.00%		
9	IBEW 57 WY							2.00%					
11	IBEW 57 PD		2.00%										
12	BEW 57 PS		2.00%										
15	BEW 57 CT		2.00%										

12 Months Ended December 2018

Group Code	Labor Group	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
3	IBEW 125		2.50%										
4	IBEW 659					2.00%							
5	UWUA 197						2.00%						
8	UWUA 127										2.50%		
9	IBEW 57 WY							2.00%					
11	IBEW 57 PD		2.00%										
12	IBEW 57 PS		2.00%										
15	IBEW 57 CT		2.00%										
16	IBEW 77		2.25%										

12 Months Ending December 2019

Group Code	Labor Group	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
3	IBEW 125	2.50%							5.10%				
4	IBEW 659					2.50%		5.10%					
5	UWUA 197						2.50%			5.80%			
8	UWUA 127										2.25%		
9	IBEW 57 WY							2.50%					
11	IBEW 57 PD		2.50%										
12	IBEW 57 PS		2.50%										
15	IBEW 57 CT		2.50%										
16	IBEW 77		2.25%										

12 Months Ending December 2020

Group Code	Labor Group	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
3	IBEW 125		2.50%										
4	IBEW 659					2.50%							
5	UWUA 197						2.50%						
8	UWUA 127										2.00%		
9	IBEW 57 WY							3.10%					
11	IBEW 57 PD		3.10%										
12	IBEW 57 PS		3.10%										
15	IBEW 57 CT		3.50%										
16	IBEW 77		2.50%										

Calendar Year	Incentive Name	Who is Eligible	Financial Performance Measurement (Goal as percent of total)	Non-Financial Performance Measurement (Goal as percent of total)	Stock Option/RSU	Total Annual Incentive Plan[1] ($000)	Estimated Oregon Allocation ($000)
Test Year	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	The scorecard is not yet available.	The scorecard is not yet available.	NA	$ 28,420	$ 8,064
Base Year	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	16.70%	83.30%	NA	NA	NA
2019	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	16.70%	83.30%	NA	$ 29,221	$ 8,275
2018	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	16.70%	83.30%	NA	$ 25,017	$ 7,090
2017	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	16.70%	83.30%	NA	$ 28,012	$ 7,954
2016	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	16.70%	83.30%	NA	$ 28,312	$ 8,124
2015	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	The company did not have a scorecard.	The company did not have a scorecard.	NA	$ 29,693	$ 8,294
2014	Annual Incentive Plan	Employees and recent retirees who meet the plan guidelines.	The company did not have a scorecard.	The company did not have a scorecard.	NA	$ 33,234	$ 9,399

1. Test Year AIP is based on the average payout ratio for calendar years 2016, 2017 and 2018 as a percentage of eligible wages. Base Year information is not available as AIP is usually paid out in December.

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF CROSS-EXHIBIT 3400

September 2, 2020

UE 374/PacifiCorp
May 8, 2020
OPUC Data Request 311

OPUC Data Request 311

Regarding PacifiCorp's coal plant Decommissioning Study for seven plants filed January 16, 2020 in Docket No. UM 1968 and for PacifiCorp's Colstrip Decommissioning Study filed March 16, 2020 in Docket No. UM 1968, please provide the percentage values PacifiCorp understands to reflect the range of an AACE International Class 3 cost estimate.

Response to OPUC Data Request 311

The Association for the Advancement of Cost Engineering International Recommended Practice No. 18R-97 indicates that the expected accuracy range is low minus 10 percent to minus 20 percent, and high plus 10 percent to plus 30 percent.

OPUC Data Request 312

Regarding PacifiCorp's coal plant Decommissioning Study ("Study") included as a confidential attachment to the Company's January 16, 2020 filing in Docket No. UM 1968, please provide:

(a) All work papers associated with the Tables listed on pages TOC – vii-viii of the Study, in Excel spreadsheet format with all cell references and formulae intact.

(b) All work papers associated with the Figures listed on pages TOC – ix of the Study, in Excel spreadsheet format with all cell references and formulae intact.

(c) The prepared cost spreadsheet ("spreadsheet report" and "working spreadsheet"), in Excel spreadsheet format with all cell references and formulae intact, for each coal plant included in the Study.

(d) The prepared demolition estimates in Appendices A through H, inclusive, for each plant, in Excel spreadsheet format with all cell references and formulae intact.

(e) The contingency percent provided by PacifiCorp's consultant(s) for each coal plant's cost estimate(s).

(f) The contingency percent used by PacifiCorp's for each coal plant's cost estimate(s) in the Company's UM 1968 filing.

(g) Any additional work papers associated with producing the Study not included in responses to "a," "b," "c," or "d" above.

(h) The "high-level design basis" template(s) used in preparing the Study.

(i) The "high-level design basis" for each coal plant included in the Study.

1st Supplemental Response to OPUC Data Request 312

In further support of PacifiCorp's May 8, 2020 Response to OPUC Data Request 312, the Company provides the following information responsive to subpart (i):

(i) Please refer to Confidential Attachment OPUC 312 1st Supplemental for erosion control and site grading requirements identified for each of the coal-fired generation sites. PacifiCorp has identified these additional documents that support the design criteria associated with the reclamation of each site.

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

OPUC Data Request 313

Regarding PacifiCorp's Colstrip coal plant Decommissioning Study ("Study") included as a confidential attachment to the Company's March 16, 2020 filing in Docket No. UM 1968, please provide:

(a) All work papers associated with any Table included in the Study, in Excel spreadsheet format with all cell references and formulae intact.

(b) All work papers associated with any Figure included in the Study, in Excel spreadsheet format with all cell references and formulae intact.

(c) The prepared Colstrip cost spreadsheet ("spreadsheet report" and "working spreadsheet") included in the Study, in Excel spreadsheet format with all cell references and formulae intact.

(d) The prepared Colstrip demolition estimates included in the Study, in Excel spreadsheet format with all cell references and formulae intact.

(e) The contingency percent provided by PacifiCorp's consultant(s) for Colstrip's cost estimate(s).

(f) The contingency percent used by PacifiCorp's for Colstrip's cost estimate(s) in the Company's UM 1968 filing.

(g) Any additional work papers associated with producing the Study not included in responses to "a," "b," "c," or "d" above.

(h) The "high-level design basis" template(s) used in preparing the Study.

(i) The "high-level design basis" for Colstrip included in the Study.

1st Supplemental Response to OPUC Data Request 313

In further support of PacifiCorp's May 8, 2020 Response to OPUC Data Request 313, the Company provides the following information responsive to subpart (i):

(i) Please refer to Confidential Attachment OPUC 313 1st Supplemental for erosion control and site grading requirements identified for Colstrip Units 3 and 4. PacifiCorp has identified these additional documents that support the design criteria associated with the reclamation of Colstrip Units 3 and 4.

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

OPUC Data Request 725

Coal Plant Decommissioning Studies' Cost Estimates
Please provide all support available to PacifiCorp for amounts in Lines 2a and 2b (for "Decommissioning – Owner scope" costs in the spreadsheet reports provided by Kiewit) for each plant included in the two Kiewit reports.

Response to OPUC Data Request 725

"Decommissioning – Owner scope" costs was based on the actual owner costs incurred for decommissioning and demolition of the Carbon generating facility adjusted for the size of the generating facility and economies of scale. Refer to Confidential Attachment OPUC 725 for the owner costs provided to Kiewit for inclusion in the study.

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

OPUC Data Request 726

Coal Plant Decommissioning Studies' Cost Estimates
Regarding PacifiCorp's characterization of the two Kiewit Decommissioning Studies as being both "independent" and "impartial" at PAC/2400, Van Engelenhoven/11, please provide, for each of the eight plants included in the Studies:

a. The dollar amount included in the "Base Estimate" that was provided by PacifiCorp.
b. The dollar amount included in the "Base Estimate" that was provided by Kiewit, another contractor, or a subcontractor, identifying the total provided by such sources as well as the amount provided by each specific source.
c. The dollar amount included in the "Other Items to Consider" estimate that was provided by PacifiCorp.
d. The dollar amount included in the "Other Items to Consider" estimate that was provided by Kiewit, another contractor, or a subcontractor, identifying total provided by such sources as well as the amount provided by each specific source.

Response to OPUC Data Request 726

a. PacifiCorp provided the values as shown in the columns labeled "Responsible Party" in the confidential workpapers supporting Exhibits PAC/1900 and PAC/1901 provided with the Company's May 28, 2020 supplemental filing in this docket (specifically the files named "Exhibit PAC 1900 Decommissioning Study Workpapers CONF.xlsx" and "Exhibit PAC 1901 Colstrip Decommissioning Workpapers CONF.xlsx"), with the following clarifications:

   PacifiCorp provided the Owner's total costs shown in the report and spreadsheets as the Category 2 subtotal. The PacifiCorp provided Owner's total costs were estimated as described in the response to OPUC Data Request 725. Kiewit provided the value for Category 2a, "Owner's Engineer – ENTIRE Project."

   PacifiCorp provided the value of 8.5 percent for "Owner AROs Indirects" shown below the Category 7 subtotal.

   PacifiCorp asked Kiewit to set the Contingency in Category 11 to 0 percent.

b. Kiewit provided the values as shown in the columns labeled "Responsible Party" in the confidential worpapers supporting Exhibit PAC/1900 and Exhibit PAC/1901.

c. PacifiCorp provided the values as shown in the columns labeled "Responsible Party" in the confidential workpapers supporting Exhibit PAC/1900 and Exhibit PAC/1901, including the following:

   PacifiCorp provided the materials and supply inventory balances for each generating facility as of November, 2019, as shown in Category 2c.

   PacifiCorp provided the make, model, acquisition cost and book values of rolling stock shown in Category 4i. PacifiCorp provided type, acquisition cost and book values of rail cars shown in Category 4j. Kiewit provided the demolition costs and the scrap values shown in the report.

   PacifiCorp provided an Internet link to the publicly available site regarding PacifiCorp landfills and Coal Combustion Residual bonds. The link address is https://www.brkenergy.com/ccr/ppw.html

   PacifiCorp provided the value for General Liabilities as shown in Category 8a.

   PacifiCorp provided the value of Coal Mine Closure as shown in Category 8b.

d. Kiewit provided the values as shown in the columns labeled "Responsible Party" in the confidential workpapers supporting Exhibit PAC/1900 and Exhibit PAC/1901.

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

UE 374/PacifiCorp
July 8, 2020
OPUC Data Request 727

OPUC Data Request 727

Coal Plant Decommissioning Studies' Cost Estimates
Regarding PacifiCorp's statement, at PAC/2400, Van Engelenhoven/13, that "the Company's previous estimates did not include site reclamation:"

a. Please identify "the Company's previous estimates" filed over the past 10 years, including the Oregon docket number, filing date, and the amount of estimated cost for site reclamation included for each such filing.
b. Please provide a detailed explanation of why the Company's previous estimates filed over the past 10 years "did not include site reclamation."

Confidential Response to OPUC Data Request 727

a. Docket: UM 1647
Filing date: January 31, 2013
Reclamation: Not separated or identified. "…current decommissioning costs of $40 per kilowatt, with the exception of Carbon plant." (Exhibit PAC/300: page 13)

Docket: UM 1968
Filing date: September 13, 2018
Reclamation: $0

Docket: UM 1968
Filing date: January 16, 2020
Reclamation: See Category 5 – Reclamation of the Thermal Power Plant Demolition Estimates prepared by Kiewit

[CONFIDENTIAL BEGINS]

[redacted]

[CONFIDENTIAL ENDS]

b. An opportunity to improve the accuracy of demolition studies was found to be including reclamation costs.

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

UE 374/PacifiCorp
July 8, 2020
OPUC Data Request 730

OPUC Data Request 730

Coal Plant Decommissioning Studies' Cost Estimates
Regarding Class 3 and Class 5 cost estimates, as at PAC/2400, Van Engelenhoven/13, please provide PacifiCorp's understanding of the range of cost estimates for each class.

Response to OPUC Data Request 730

The AACE International, formerly the Association for the Advancement of Cost Estimated, describes a Class 5 estimate's primary characteristic as 0 percent to 2 percent level of project definition, expressed as a percent of complete definition. AACE International describes the secondary characteristics as having: 1) the end usage as conceptual screening; 2) the methodology as capacity factored, parametric models, judgement or analogy; 3) expected accuracy range of low: minus 20 percent to minus 50 percent, high: plus 30 percent to plus 100 percent; and 4) the preparation effort of 1.

The AACE International describes a Class 3 estimate's primary characteristic as 10 percent to 40 percent level of project definition, expressed as a percent of complete definition. AACE International describes the secondary characteristics as having 1) the end usage as budget, authorization or control; 2) the methodology as mixed, but primarily stochastic; 3) expected accuracy range of low: minus 5 percent to minus 15 percent, high: plus 5 percent to plus 20 percent; and 4) the preparation effort of 4 to 20.

UE 374/PacifiCorp
August 27, 2020
OPUC Data Request 794

OPUC Data Request 794

Coal Plant Decommissioning Cost Estimates - Please provide PacifiCorp's understanding of each of the following terms, as pertaining to the decommissioning of coal plants:

a. "Site remediation"
b. "Site reclamation"
c. "Final site cleanup and restoration"

Response to OPUC Data Request 794

a. Site remediation:
Cleanup or other methods used to remove or contain a toxic spill or hazardous materials from a hazardous waste site[1].
The return of land to the original uncontaminated state[2].

b. Site reclamation:
Process of restoring surface environment to acceptable pre-existing conditions, including surface contouring, re-vegetation, etc.[3]

c. Final site cleanup and restoration:
The process of removing debris and waste, grading the area to cover excavations resulting from demolition, and eliminating safety hazards such as protruding materials and pits.

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[1] *See e.g.* RCRA Glossary of Terms, https://ofmpub.epa.gov/sor_internet/registry/termreg/searchandretrieve/glossariesandkeywordlists/search.do?details=&vocabName=RCRA%20Glossary%20of%20Terms.

[2] *See e.g.* EPA EV-Environmental Events-Clean-up & Remediation, https://ofmpub.epa.gov/sor_internet/registry/termreg/searchandretrieve/enterprisevocabulary/search.do?toLocation=1006408&toLocationTerm=4426868.

[3] Id.

OPUC Data Request 796

Coal Plant Decommissioning Cost Estimates - Please discuss which of the following terms are generally considered to be included as costs involved in the decommissioning of U.S. coal plants:
a. "Site remediation"
b. "Site reclamation"
c. "Final site cleanup and restoration"

Response to OPUC Data Request 796

The state of a former generating facility varies widely depending on many conditions and circumstances. A brief survey of former generating facilities will find everything from generating facilities converted to museums, facilities on the National Register of Historic Places, facilities that have been repurposed, facilities that have been reclaimed, to facilities that have been abandoned and left to rot.

a. Site remediation is required by state or federal regulation or both[1][2][3]. The Resource Conservation and Recovery Act and associated regulations[4] are the federal regulations governing remediation.

b. Site reclamation is often included in the decommissioning of U.S. coal-fired generating facilities. Reclamation may be required by regulation or contract. Even in the absence of a requirement via regulation or contract, reclamation is often performed because of good citizenship, respect for local communities, and a respect for the environment. PacifiCorp reclaimed the Carbon generating facility and associated sites.

c. Site cleanup and restoration is typically performed as part of the decommissioning of U.S. coal-fueled generating facilities. Cleanup and restoration is often required by local regulation.

[1] 42 U.S.C. §6901 et seq. (1976).
[2] Utah Code Title 19 Chapter 6.
[3] Wyoming Environmental Quality Act, W.S. 35-11-101 et seq.
[4] 40 CFR 239 through 282.

UE 374/PacifiCorp
August 27, 2020
OPUC Data Request 797

OPUC Data Request 797

Coal Plant Decommissioning Cost Estimates - Please discuss which of the following terms PacifiCorp considers to be included as costs involved in the decommissioning of the Company's coal plants:

(a) "Site remediation".

(b) "Site reclamation".

(c) "Final site cleanup and restoration".

Response to OPUC Data Request 797

All of the terms were included in the decommissioning of the Carbon generating facility, and are included in cost estimates for decommissioning PacifiCorp's remaining coal-fueled generating facilities.

OPUC Data Request 799

Coal Plant Decommissioning Cost Estimates - Regarding the 2020 Protocol's "costs of removal and environmental remediation or reclamation" definition, please 1) identify those elements or activities that are included in "environmental remediation" that are not included in "environmental reclamation" and 2) identify those elements or activities that are included in "environmental reclamation" that are not included in "environmental remediation."

Response to OPUC Data Request 799

1) Site remediation:
   Cleanup or other methods used to remove or contain a toxic spill or hazardous materials from a hazardous waste site[1].
   The return of land to the original uncontaminated state[2].
   No elements of environmental remediation are included in environmental reclamation.

2) Site reclamation:
   Process of restoring surface environment to acceptable pre-existing conditions. Includes surface contouring… re-vegetation, etc.[3]
   No elements of environmental reclamation are included in environmental remediation.

[1] RCRA Glossary of Terms, https://ofmpub.epa.gov/sor_internet/registry/termreg/searchandretrieve/glossariesandkeywordlists/search.do?details=&vocabName=RCRA%20Glossary%20of%20Terms
[2] EPA EV-Environmental Events-Clean-up & Remediation, https://ofmpub.epa.gov/sor_internet/registry/termreg/searchandretrieve/enterprisevocabulary/search.do?toLocation=1006408&toLocationTerm=4426868
[3] ibid

OPUC Data Request 800

Coal Plant Decommissioning Cost Estimates - Is it PacifiCorp's position that, of all the activities and costs incurred related to the shutdown and ceasing of operations ("permanent cessation of operations" or "permanent cessation of receipt of energy" or "otherwise retirement") of a PacifiCorp coal plant or unit thereof, only future decommissioning costs *per se* are properly included in the net salvage component of depreciation expense? If this is not PacifiCorp's position, please explain.

Response to OPUC Data Request 800

The decommissioning costs that are properly included in the net salvage component of the depreciation rates of the Company are the costs to decommission, decontaminate, demolish, and reclaim the sites of the Company's coal-fired plants.

OPUC Data Request 801

Coal Plant Decommissioning Cost Estimates - Regarding PAC/3900, Van Engelenhoven/8 line 7 – Van Engelenhoven/9 line 11, please identify which of the following include the estimated costs of 1) "site remediation," 2) "site reclamation," 3) "final site cleanup and restoration," 4) both "site remediation" and "site reclamation; and 5) any other combination of "site remediation," "site reclamation," and/or "final site cleanup and restoration"—specifying the combination(s) included:"

(a) The "original decommissioning study…performed in the 2014 and 2016 time frame";

(b) PacifiCorp's initial filing in UM 1968;

(c) The "2017 demolition study";

(d) The Kiewit reports.

Response to OPUC Data Request 801

Referencing the criteria referenced in this request, namely:

(1) "site remediation,"
(2) "site reclamation,"
(3) "final site cleanup and restoration,"
(4) both "site remediation" and "site reclamation; and
(5) any other combination of "site remediation," "site reclamation," and/or "final site cleanup and restoration,"

the Company responds as follows:

(a) The "original decommissioning study… performed in 2014 and 2016 time frame" includes: (1) site remediation, and (3) final site clean-up and restoration.

(b) PacifiCorp's initial filing in docket UM 1968 includes: (1) site remediation, and (3) final site clean-up and restoration.

(c) The "2017 demolition study" includes: (1) site remediation, and (3) final site clean-up and restoration.

(d) The Kiewit reports include: (1) site remediation, (2) site reclamation, and (3) final site clean-up and restoration.

UE 374/PacifiCorp
August 27, 2020
OPUC Data Request 803

OPUC Data Request 803

Coal Plant Decommissioning Cost Estimates - Please identify each PacifiCorp Oregon proceeding filed in or after 2010 that included the estimated costs of "site reclamation" for the Company's coal plants.

Response to OPUC Data Request 803

Other than the current proceeding, the only proceeding in or after 2010 PacifiCorp filed that included discussion and estimates of decommissioning costs was docket UM 1647, filed in January 2013. For the purposes of the Company's depreciation rate calculations, decommissioning costs refer to the costs of removing facilities that have been retired *and* restoring the site to its original grade.

UE 374/PacifiCorp
August 27, 2020
OPUC Data Request 804

OPUC Data Request 804

Coal Plant Decommissioning Cost Estimates - Please identify the last three PacifiCorp Oregon proceedings prior to UM 1968 and UE 374 that included the estimated costs of "site reclamation" for the Company's coal plants, citing the location(s) in the Company's testimony that discussed "site reclamation" in each such proceeding.

Response to OPUC Data Request 804

Docket No.	Discussion on "decommissioning costs" ǂ
UM 1647	Exhibit PAC/300, starting at Andrews/13
UM 1329	Exhibit PPL/200, starting at Mansfield/11
UM 1064	Exhibit PPL/300, starting at Cunningham/16

ǂ Decommissioning costs reflected in the Company's depreciation rates encompasses the costs of removing facilities that have been retired, as well as restoring the site to its original grade.

UE 374/PacifiCorp
August 27, 2020
OPUC Data Request 807

OPUC Data Request 807

Coal Plant Decommissioning Cost Estimates - Regarding PAC/400, Teply/11 in Docket No. UM 1968, estimated costs for which of the following were included in the $40 per kilowatt value previously used to estimate "decommissioning costs" for PacifiCorp's coal plants:

(a) "Site remediation".

(b) "Site reclamation".

(c) "Final site cleanup and restoration".

Response to OPUC Data Request 807

The estimated costs include the $40 per kilowatt ($/kW) value in docket UM 1968 included (a) "Site remediation," and (c) "Final site cleanup and restoration."

UE 374/PacifiCorp
August 27, 2020
OPUC Data Request 809

OPUC Data Request 809

Coal Plant Decommissioning Cost Estimates - Regarding PAC/3900, Van Engelenhoven/11 lines 1 – 11, please specify which of the estimated costs included as "Other Costs" are appropriate to include in the decommissioning costs of a coal plant.

Response to OPUC Data Request 809

As stated in Exhibit PAC/3900, Van Engelenhoven/11 lines 1–11, the costs included in the decommissioning studies are broken into two categories, (1) the base estimate to decommission, decontaminate, demolish, and reclaim the site; and (2) "Other Items to be Considered." All costs included in the decommissioning studies, including the "Other Items to be Considered" are appropriate to include in the decommissioning costs of a coal plant.

UE 374/PacifiCorp
August 27, 2020
OPUC Data Request 811

OPUC Data Request 811

Coal Plant Decommissioning Cost Estimates - Regarding PAC/3900, Van Engelenhoven/11 lines 1 – 11, please specify those costs included as "Other Costs" for which PacifiCorp will request recovery in a future proceeding from its Oregon ratepayers with respect to the PacifiCorp coal plants that continue to operate after Oregon exits.

Response to OPUC Data Request 811

Oregon's allocated share of "Other Costs" identified in the updated decommissioning studies prepared by Kiewit Engineering Group, Inc. for the following coal plants have been included in its entirety in the Company's request for recovery in the current general rate case:

- Hunter
- Huntington
- Dave Johnston
- Jim Bridger
- Naughton
- Wyodak
- Hayden

Recovery of the Oregon allocated share of "Other Costs" for Colstrip plant will be requested in a future proceeding.

UE 374/PacifiCorp
August 27, 2020
OPUC Data Request 819

OPUC Data Request 819

Coal Plant Decommissioning Cost Estimates - Regarding PAC/3900, Van Engelenhoven/14 lines 18 – 24, please:

(a) List those line item costs provided by PacifiCorp, distinguishing between those that are “Base Estimates” and those that are “Other Costs,” and between coal plants (or coal plant units where relevant).

(b) Separately for each line item cost listed in response to “a” (above), please indicate whether PacifiCorp provided documentation supporting the estimated cost.

(c) Separately for each line item cost listed in response to “b” (above), please identify each document provided by PacifiCorp in support of the estimated cost, including the format(s), date(s), and proceeding(s) in which it was provided.

Response to OPUC Data Request 819

(a) PacifiCorp provided the Owner’s Costs (Category 2), Asset Retirement Obligations (ARO) (Category 7), Owner AROs Indirects (Category 7), and PacifiCorp Ownership Percentage (Category 13) which appear in the Base Estimates portion of the report.

PacifiCorp provided the Writedown of Materials and Supply (M&S) Inventory (Category 2 item c), Rolling Stock (Category 4, Item i), Railcars (Category 4, Item j), and General Liabilities (Category 8, Item a), and PacifiCorp Ownership Percentage (Category 13) in the Other Costs portion of the report.

(b) PacifiCorp provided documentation for Owner’s Costs (Category 2), Asset Retirement Obligations (Category 7) in response to OPUC Data Request 786 and the responses identified therein.

(c) PacifiCorp provided documentation for Owner’s Costs (Category 2), Asset Retirement Obligations (Category 7) in response to OPUC Data Request 786 and the responses identified therein.

UE 374/PacifiCorp
August 27, 2020
OPUC Data Request 824

OPUC Data Request 824

Coal Plant Decommissioning Cost Estimates - Regarding PAC/3900, Van Engelenhoven/19 and the non-asbestos AROs, please indicate whether these costs were included in the $40 per kilowatt value previously used to estimate the costs of decommissioning PacifiCorp's coal plants.

Response to OPUC Data Request 824

The then-current Asset Retirement Obligations were included in the 2018 filing.

UE 374/PacifiCorp
May 29, 2020
OPUC Data Request 530

OPUC Data Request 530

Transmission
Please provide one-line diagrams of all projects listed in PAC/1000, Vail/11. For projects in which the Company has already provided Staff with one-line diagrams, please refer Staff to the appropriate discovery attachments and responses.

Response to OPUC Data Request 530

Please refer to the one line diagrams for each of the projects included as exhibits PAC/1001-PAC/1009 in the testimony of Richard A. Vail.

UE 374/PacifiCorp
May 21, 2020
OPUC Data Request 471

OPUC Data Request 471

Transmission
For all projects listed in PAC/1000/Vail/11, please identify:

(a) Whether there were any studies performed assigning reliability costs.

(b) Please provide all such studies.

Response to OPUC Data Request 471

Referencing the direct testimony of Rick A. Vail, specifically page 11, Table 1, the Company responds with regard to the listed transmission projects:

(a) There are no studies assigning reliability costs. PacifiCorp is obligated to maintain reliability in compliance with the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation and the Western Electricity Coordinating Council standards and criteria.

(b) See response to (a) above.

OPUC Data Request 499

Transmission
Regarding current events pertaining to the novel coronavirus and transmission project completions:

(a) Is the Company aware of any supply chain challenges due to the novel coronavirus that will impact any transmission and generation projects requested in this rate case? For example, if a transformer with an anticipated delivery date of 6/10/2020 is likely to be held up due to international global supply chain issues.

(b) If the Company is aware of any current challenges that would impact the in-service date of any transmission or generation project, please provide all internal memos, analytics, presentations, work papers, and communications identifying these challenges. This is an ongoing request, that is not terminated until each applicable project is energize and in service.

Confidential Response to OPUC Data Request 499

(a) **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**.

The Company is not aware of any supply chain challenges due to COVID-19 pandemic that will impact any transmission projects.

(b) The Company objects to this request to the extent that it requests privileged documents. Notwithstanding this objection, the Company responds as follows:

[CONFIDENTIAL BEGINS] [redacted]

[redacted] **CONFIDENTIAL ENDS]**.

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

OPUC Data Request 826

Transmission - Please see PAC/4200, Vail/10, lines 8-9. The Company states, "Original estimates try to anticipate these costs, but it is impossible to account for them all." Please also see Vail/11, lines 13-16. The Company states, "As discussed above, however, the mere fact that costs increased as circumstances on the ground changed does not demonstrate that the Company was imprudent or that the increased costs should be disallowed." See also PAC/4200, Vail/20, lines 15-16. The Company states, "Staff then arbitrarily assigns the risk exclusively to the utility." Is it the Company's position that:

a. All cost overruns should be borne by ratepayers in in all circumstances?
b. Cost overruns should be borne by ratepayers in the event that the Company failed to control costs?
c. All cost overruns and risks should be assigned to ratepayers for primary or secondary contractor error?
d. All cost overruns and risks should be assigned to ratepayers for engineering planning failures?

Response to OPUC Data Request 826

PacifiCorp objects to the data request as vague and requesting information that may be beyond the scope of the current proceeding. Without waiving this objection, PacifiCorp responds as follows:

a. No. PacifiCorp has not asserted that "all cost overruns should be borne by ratepayers in all circumstances." PacifiCorp is seeking recovery of only prudently incurred costs. PacifiCorp's position is that the Commission's prudence standard applies to all investments, including investments where the actual costs exceed preliminary estimates. In accordance with the Commission's prudence standard, PacifiCorp's decision to invest in the transmission projects in this case and PacifiCorp's management of the development and construction of those projects, including PacifiCorp's response to changed circumstances, were prudent and objectively reasonable based on what PacifiCorp knew or should have known when the decisions were made.

b. No. PacifiCorp has not asserted that "cost overruns should be borne by ratepayers in the event that the Company failed to control costs." PacifiCorp is seeking recovery of only prudently incurred costs. PacifiCorp's position is that the Commission's prudence standard applies to all investments, including investments where the actual costs exceed preliminary estimates. In accordance with the Commission's prudence standard, PacifiCorp's decision to invest in the transmission projects in this case and PacifiCorp's management of the development and construction of those projects, including PacifiCorp's response to changed circumstances, were prudent and objectively reasonable based on what PacifiCorp knew or should have known when the decisions were made.

c. No. PacifiCorp has not asserted that "all cost overruns and risks should be assigned to ratepayers for primary or secondary contractor error." PacifiCorp is seeking recovery of only prudently incurred costs. PacifiCorp's position is that the Commission's prudence standard applies to all investments, including investments where the actual costs exceed preliminary estimates. In accordance with the Commission's prudence standard, PacifiCorp's decision to invest in the transmission projects in this case and PacifiCorp's management of the development and construction of those projects, including PacifiCorp's response to changed circumstances, were prudent and objectively reasonable based on what PacifiCorp knew or should have known when the decisions were made.

d. No. PacifiCorp has not asserted that "all cost overruns and risks should be assigned to ratepayers for engineering planning failures." PacifiCorp is seeking recovery of only prudently incurred costs. PacifiCorp's position is that the Commission's prudence standard applies to all investments, including investments where the actual costs exceed preliminary estimates. In accordance with the Commission's prudence standard, PacifiCorp's decision to invest in the transmission projects in this case and PacifiCorp's management of the development and construction of those projects, including PacifiCorp's response to changed circumstances, were prudent and objectively reasonable based on what PacifiCorp knew or should have known when the decisions were made.

OPUC Data Request 827

Transmission - Regarding low-voltage system assets:

a. To PacifiCorp's knowledge, has the Company ever asked for, and subsequently received, cost recovery for low-voltage assets on a system basis? For example, for an asset that the Company has designated as a system resource, has the Company received cost recovery for such a resource located in a non-Oregon jurisdiction when the size of the resource is low-voltage (e.g., a 46kV line)?
b. Has the Company ever been denied cost recovery outside of Oregon for a system-allocated resource that is low-voltage (for example, a 46 kV line). Please provide an explanation and examples, as relevant. If there are numerous examples, please provide five.
c. Has the Company ever been denied cost recovery inside of Oregon for a system-allocated resource that is low-voltage (for example, a 46 kV line). Please provide an explanation and examples, as relevant. If there are numerous examples, please provide five.

Response to OPUC Data Request 827

PacifiCorp objects to this data request as overly broad and unduly burdensome as it seeks information that is publically available. Without waiving the objection, PacifiCorp responds as follows:

a. Yes. The Company has an approved allocation method that functionalizes transmission assets that operate at 46 kilovolts and above as transmission plant, in accordance with PacifiCorp's Federal Energy Regulatory Commission-approved Open Access Transmission Tariff.

b. PacifiCorp has not conducted an exhaustive search through its history as a public utility, but the Company is not aware of any examples of disallowances based on voltage. PacifiCorp was subject to the Western Control Area allocation methodology in Washington that did not allocate the costs of system resources located in PacifiCorp's eastern balancing authority area.

c. PacifiCorp has not conducted an exhaustive search through its history as a public utility, but the Company is not aware of any examples of disallowances based on voltage.

UE 374/PacifiCorp
August 28, 2020
OPUC Data Request 828

OPUC Data Request 828

> **Transmission** - To PacifiCorp's knowledge, does the Company have any recollection of higher-voltage (e.g., above 200 kV) assets that were asked for at filing in previous Oregon rate cases, but not authorized in rate base as Ordered by the Oregon Commission?

Response to OPUC Data Request 828

> PacifiCorp objects to this data request as unduly burdensome as it seeks information that is equally available to Staff. Without waiving the objection, PacifiCorp responds as follows:
>
> PacifiCorp has not conducted an exhaustive search through its history as a public utility, but the Company is not aware of any examples of disallowances based on voltage.

OPUC Data Request 830

Transmission - Please see PAC/4200, Vail/35-36. The Company states, "The Utah State Prison project furthers the transmission master plan by providing a 138 kV tie to an eventual 500/345/138 kV substation in the Tooele, Utah area. This tie will provide additional transmission path capacity and reliability to the bulk electric transmission system."

a. Please provide the "transmission master plan."
b. Is it the Company's position that intending to build future transmission (that does not currently exist) is enough of a justification for used and usefulness of an associated project? That is, the prison project's role in a yet-to-be-built substation means that the prison project should be considered a "system" project?
c. Is it generally the Company's position to justify used and usefulness of current projects based on nonexistent future projects?

Response to OPUC Data Request 830

a. Please refer to Confidential Attachment OPUC 830.

b. PacifiCorp objects to this data request as vague and speculative. The Utah State Prison Project is currently used and useful because it has been energized and placed in service and provides customer benefits as a component of PacifiCorp's transmission system. PacifiCorp's transmission system, as a whole, is used and useful because the transmission system is required to allow the Company to provide service to Oregon customers. The transmission system allows PacifiCorp to dispatch its generation resources and energy from power purchase agreements and provides PacifiCorp access to wholesale energy markets. PacifiCorp's transmission system also provides revenue credits from third-party wholesale transmission sales that decrease Oregon retail rates. The Utah State Prison Project will be included PacifiCorp's transmission rates and Oregon customers will receive revenue credits based on the Utah State Prison Project.

   Prudent utility operation requires the Company to anticipate and plan for future resource needs, including transmission system needs, and for the orderly sequencing of resource construction to ensure current projects align with future resource needs and transmission plans. Once a transmission project is in service, the project promotes the reliability and transfer of energy across the transmission system as a whole. This ensures the Company maximizes transmission path capacity and optimizes system reliability for the bulk electric transmission system. The 138 kV tie to the future Tooele substation was cited as an example of how the Utah State

Prison Project ties into and strengthens the bulk electric system but was not intended to suggest that the only benefit associated with the Utah State Prison Project was its potential tie to the Tooele substation. The fact that a currently operational transmission asset is also a component of a longer-term transmission plan does not mean that the currently operational asset is not used and useful until the later-built transmission assets are placed in-service.

c. See response to OPUC Data Request 830(b).

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

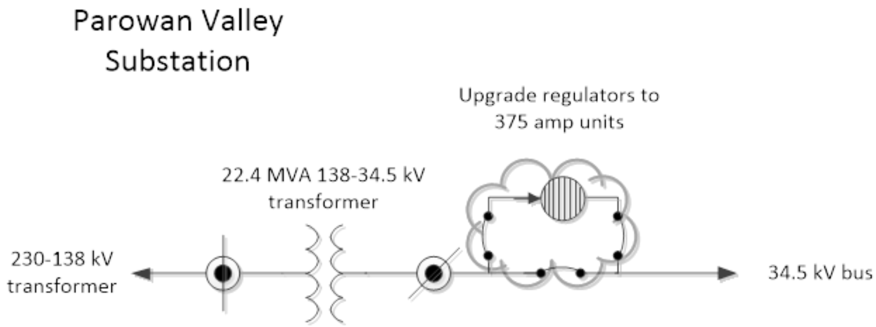
OPUC Data Request 831

Transmission - Please see PAC/4400, McCoy 7-8. The Company states, “Finally, two items in the pro forma transmission plant were misclassified as transmission and were system allocated. One of the projects should have been situs assigned to Utah. The second should have been situs assigned to Oregon. The changes associated with these projects would decrease rate base from the system allocation of approximately $1.7 million, combined, to a 100 percent situs allocation of $768,748 to Oregon. PacifiCorp estimates the impact of these changes to be a reduction to Oregon revenue requirement of approximately $500,000.”

a. For each of these projects, please provide:
    i. A detailed description of what these projects are
    ii. Project voltages
    iii. In-service dates
    iv. Interconnection studies
    v. Contracts
    vi. Exact locations or maps of where these projects are located
    vii. One-line diagrams
b. Please provide a detailed narrative as to why these projects were originally misclassified.
c. Please provide a detailed narrative as to why the Company now believes these projects should be situs-assigned to Utah and Oregon, respectively.
d. Please explain the process by which the Company discovered that these were misclassified.

Response to OPUC Data Request 831

a. <u>Project 1: Parowan Valley Reg Replacement</u>
    i. This project will replace the existing 34.5 kilovolt (kV) regulators at Parowan Valley substation with larger units. Due to area load growth, the existing regulators are projected to overload.
    ii. 34.5 kV
    iii. December, 31, 2020
    iv. N/A – not associated with an interconnection request
    v. N/A – this project has not been started
    vi. Parowan Valley substation located approximately five miles northwest of Parowan Valley, Utah

vii. 

<u>Project 2: Block 216 Tower</u>

i. This project is to provide customer requested new load for a mixed use residential/commercial 35 story tower located at 900 SW Washington Street in Portland Oregon.
ii. The customer requested service voltages are 277/480 volts and 120/208 volts.
iii. The current project in service date is October 1, 2020, however the customer is not ready to proceed at this time due to COVID-19 related construction delays. The customer is now indicating they will be ready to accept service October 1, 2022.
iv. Please refer to the file, "BED SW Washington Street LLC_Block 216_SIS_FINAL_CONF" provided with the Company's response to OPUC Data Request 225 (Confidential Attachment OPUC 225-2).
v. Please refer to Confidential Attachment OPUC 831 for copies of the Electric Service Study Agreement and the Master Electric Service and Facilities Improvements Agreement.
vi. The map of the customer project and improvements needed to serve the customer is included in the study referenced in subpart iv, above.

b. As project information was being entered into our 10 year planning database, the Federal Energy Regulatory Commission category was incorrectly chosen as transmission. Other project documentation identified this project as a distribution class project so it appears this misclassification was a typo during data entry and never got corrected prior to the plan being finalized.

c. These projects should be situs assigned because they are now identified as distribution plant. The 2020 Protocol states that all distribution-related expenses and investments that can be directly allocated will be directly allocated to the state where they are located. See section 3.1.4 and 5.3 of the Oregon approved 2020 Protocol.

d. The error was found during the preparation of docket UE 374 surrebuttal testimony.

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

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF CROSS-EXHIBIT 3600

September 2, 2020

OPUC Data Request 793

SCRs, Environmental Compliance - Please refer to the Company's response to Staff Data Request 750. Please refer to the attachment "OPUC 750 1st REV CONF Attach."

a. Please refer to the tab labeled "Bridger U3 & U4 SCRS."
   i. Please reconcile the deprecation rates for Jim Bridger as listed in cells B6 and B7, with the depreciation rates for Jim Bridger as listed in Appendix A of Order No. 13-347 issued in Docket No. UM 1647.
   ii. Please provide the depreciable life PacifiCorp assumed for the SCR investments at Bridger Units 3 & 4, as well as the Oregon depreciable life of the plant itself. If these dates are different, please explain the Company's rationale for using different depreciable lives.

b. Please refer to the tab labeled "Craig_Hayden_Hunter." For each of the following projects, please provide the depreciable life PacifiCorp assumed for the environmental compliance investments, as well as the Oregon depreciable life of the plant itself. If these dates are different, please explain the Company's rationale for using different depreciable lives:
   i. Craig 2: SCR System
   ii. Hayden 1: SCR INSTALLATION;
   iii. Hayden 2: SCR INSTALLATION;
   iv. Hunter U1 Clean Air-PM; and
   v. Hunter U1 NOX LNB Clean Air.

Response to OPUC Data Request 793

a. Please refer to the tab labeled "Bridger U3 & U4 SCRS."
   i. The depreciation rates used in Confidential Attachment OPUC 750 1st Revised are composite depreciation rates. The composite depreciation rates were based on the approved depreciation rates listed in Appendix A. of Order No. 13-347 issued in Docket UM 1647. The composite rates were calculated using the approved depreciation rates multiplied by the Gross Plant June 2019 plant balances grouped by plant function and allocation factor. Please refer to Attachment OPUC 320-1, tab Composite Rates OR, cells G62 and G18. They match the composite rates used in Confidential Attachment OPUC 750 1st Revised cells B6 and B5 respectively.

ii. When the selective catalytic reduction (SCR) system investments at Bridger Units 3 and 4 were placed into service they adopted group depreciation rates, as approved in the last Oregon Depreciation Study (Docket UM 1647), that were based on the Oregon depreciable life of 2025 for the plant itself. These depreciation rates will remain in place until the next Depreciation Study is approved by the Commission. For the purposes of providing depreciation expense in response to OPUC 750, depreciation was calculated manually by applying the approved rates to the gross balance of the SCR investments.

b. The environmental compliance investments that were placed into service at Craig 2, Hayden 1, Hayden 2 and Hunter 1 adopted group depreciation rates, as approved in the last Oregon Depreciation Study (Docket UM 1647), that were based on the Oregon depreciable lives for those plants:

   i. Craig - 2026
   ii. Hayden - 2023
   iii. Hayden - 2023
   iv. Hunter - 2029
   v. Hunter – 2029

   These depreciation rates will remain in place until the next Depreciation Study is approved by the Commission. For the purposes of providing depreciation expense in response to OPUC 750, depreciation was calculated manually by applying the approved rates to the gross balance of the environmental compliance investments.

PUBLIC UTILITY COMMISSION

OF

OREGON

STAFF CROSS-EXHIBIT 3700

September 2, 2020

OPUC Data Request 515

Wildfire Mitigation
Referencing PAC/1100, Lucas/6, Table 1 identify the number of transmission and distribution substations within the Oregon Fire High Consequence Areas (FHCA) with and without System Control and Data Acquisition (SCADA) indication and control for advanced protection and control relaying.

Response to OPUC Data Request 515

Based on the fire threat mapping process conducted by PacifiCorp, approximately 26 of the Company's distribution and transmission substations are located within the Oregon Fire High Consequences Areas (FHCA). However, it is critical to note that when considering fire mitigation or system hardening projects and programs, circumstances may exists where a given substation may not be geographically located within the FHCA but is electrically connected and provides electric service to a circuit that is wholly or partially located within the FHCA. In these scenarios, investment at the substation may be critical to reduce the risk of wildfire on the circuit or properly coordinate and facilitate risk reducing system hardening projects or programs implemented out on the circuit.

With regard to System Control and Data Acquisition (SCADA), approximately 75 percent of PacifiCorp's substations within Oregon have SCADA capability/functionality of some sort. This connectivity can include either visibility into assets and monitoring capability or control of assets or both. Specific to wildfire mitigation programs or projects, it is critical to note that existing SCADA capability does not necessarily imply that available capacity exists to incorporate new equipment or elements, nor does it imply direct compatibility with new technologies being implemented out on the circuit. For each substation project, detailed engineering is required to fully evaluate existing capacity and compatibility and determined the scope of requirements.

The following table includes the number of substation located within the FHCA or electrically connected to circuits within the FHCA as well as the number of these substations with existing SCADA capability of some sort.

Type of Substation	Number of Substations	Number with SCADA Capability
Located within the FHCA	26	22
Electrically Connected to Circuits within the FHCA but not located within the FHCA	34	22
Total	60	44

OPUC Data Request 761

Wildfire Mitigation
Referencing PAC/688, 688-2 Attachment, Page 81 /Line 16 identify the current number of operational Remote Access Reclosers (RARs) beyond the substation with remote indication and operations capability inside the Oregon Fire High Consequence Area (FHCA) and outside the FHCA however electrically connected to the FHCA. State separately the number inside the FHCA and the number outside but electrically connected to the FHCA.

Response to OPUC Data Request 761

Currently no reclosers within the Oregon Fire High Consequence Area (FHCA) or electrically connected to the FHCA have remote operability.

OPUC Data Request 762

Wildfire Mitigation
Referencing PAC/688, 688-2 Attachment, Page 81/Line 16 identify the number of Remote Access Reclosers (RARs) without remote indication and operations capability inside the Oregon FHCA and electrically connected to the FHCA. State separately the number inside the FHCA and the number outside but electrically connected to the FHCA.

Response to OPUC Data Request 762

There are currently 103 reclosers without remote operations both within and electrically connected to the Oregon Fire High Consequence Area (FHCA). The list below distinguishes between segments protected by a recloser that have a presence within the FHCA, as well as those reclosers which zones are only electrically connected to circuit having zones within an FHCA.

	Recloser zone within FHCA	Electrically connected	Total
Current	65	38	103
Future Total	65	39	104
Future-remotely operable	60	37	97

UE 374/PacifiCorp
August 26, 2020
OPUC Data Request 792

OPUC Data Request 792

Wildfire Mitigation - Referencing to Exhibit PAC/3300, Lockey/36, lines 11-17, please provide: a) a numerical one-to-one mapping/transformation relating each year's number of Staff clearance violations as displayed in Staff/2700, Moore/4, to the normalized audit miles approach value; b) For the Violation Levels I, II and III, as discussed in Staff/2700, Moore 8-9, please provide what values using the audit-miles approach, Violations I, II and III would equal. Please provide all work papers with cell references and formula intact used to calculate the answers to this question.

Response to OPUC Data Request 792

Please refer to Attachment OPUC 792.

a) See cells B12 through S12.

To determine the normalized error rate of historical violations, PacifiCorp assumed that each year one-third of the Oregon overhead line spans were audited. Using an average span length of 300 feet and an overhead line miles of 14,359, the one-third span value was calculated to be 84,239 spans. The violations were then divided by the one-third span value to determine the normalized annual error rate.

b) See cells B19 through D19.

To calculate the Violation Levels I, II and III using a normalized audit-miles approach, Violation Level III was set at 0.3 percent (250 violations) and then the same violation reduction for Violation Level I and Level 2 was assumed as proposed by Staff.

Company Proposed Normalized Spans/99.7% accuracy rate	Company Proposal	
Oregon Tax Report Mileage 2019	14,359	
Average Span Length (ft)	300	
Calculated Oregon Spans	252,718	
Spans Evaluated Annually (1/3 of system per OPUC Safety Staff)	**84,239**	*Normalizing Variable: Number of spans audited in a year*
Spans with violations based on Proposed Base Threshold Error Rate	252	
Proposed Base Threshold Error Rate	0.30%	

Violation History:	2003	2004	2005	2006	2007	2008	2009	2010	2011
Vegetation Violations found during staff audit	58	177	93	34	42	73	122	87	90
Error Rate using Normalized Spans Method (using 2019 mileage/spans)	0.07%	0.21%	0.11%	0.04%	0.05%	0.09%	0.14%	0.10%	0.11%

Violation History:	2012	2013	2014	2015	2016	2017	2018	2019	2020
Vegetation Violations found during staff audit	101	280	383	364	191	322	195	502	373
Error Rate using Normalized Spans Method (using 2019 mileage/spans)	0.12%	0.33%	0.45%	0.43%	0.23%	0.38%	0.23%	0.60%	0.44%

Moore Proposal Violation Level	VL1	VL2	VL3
Threshold Spans with Violations	75	150	200

PacifiCorp Proposal Violation Level/Normalized Spans	VL1	VL2	VL3*
Performance Threshold Error Rate	0.15%	0.24%	0.30%
Threshold Spans with Violations	125	200	250

** Assumes VL3 to be at 0.3% Error Rate and then the same Violation reduction to get to VL1 and VL2 as proposed by staff*