Docket No. 25-035-47
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Rick T. Link

August 2025

I. INTRODUCTION

Q. Please state your name, business address and present position with PacifiCorp dba Rocky Mountain Power ("Company").

A. My name is Rick T. Link, my business address is 825 NE Multnomah Street, Suite LCT 600, Portland, Oregon 97232. I am currently employed as Senior Vice President, Resource Planning and Procurement.

II. QUALIFICATIONS

Q. Please summarize your education and business experience.

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

III. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe and support the Company's new inter-jurisdictional cost-allocation methodology, the 2026 PacifiCorp Inter-Jurisdictional Allocation Protocol ("2026 Protocol") for use in Utah, Idaho, Wyoming, California and Oregon (collectively, the "Five States"). I discuss the Company's previous cost-allocation methodology developed through the Multi-State Process ("MSP") and summarize the standards the Public Service Commission of Utah ("Commission") has applied in reviewing these past methodologies. I explain the Company's phased filing of its new inter-jurisdictional cost-allocation methodology, beginning with the Washington 2026 Protocol in April 2025, and the filing of the 2026 Protocol in Utah and other states in July 2025. I outline the specific provisions of the 2026 Protocol and explain how the recommended modifications to the current allocation methodology, the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (the "2020 Protocol") approved in docket 19-035-42[1] and extended in docket 23-035-20,[2] will produce rates that are just and reasonable, and provide benefits to Utah customers.

Q. Please summarize your testimony.

A. The Company is proposing a new cost allocation methodology, the 2026 Protocol, to replace the expiring 2020 Protocol, realign resources in light of state disallowances of carbon costs, comply with state law, and set the stage for future cost-allocation changes that support diverging state policies. In this filing, the Company proposes allocations based

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[1] *Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 19-035-42, Order Approving 2020 Protocol (Apr. 15, 2020).

[2] *Application of Rocky Mountain Power for Approval of an Extension to the 2020 Inter-Jurisdictional Cost Allocation Agreement,* Docket No. 23-035-20, Order Approving Extension of the 2020 Protocol (Jul. 27, 2023).

on two resource portfolios—one portfolio for resource allocations to Utah, Idaho, Wyoming, California, and Oregon (the "Five-State Portfolio") and one portfolio for a fixed allocation of resources to Washington (the "Washington Fixed Portfolio"). Together, the portfolios fully allocate all existing resources. Costs for existing resources in the Five-State Portfolio will continue to be dynamically allocated to the Five States.

Because of unique state energy policies, compliance timelines, and the inherent complexity in transitioning from dynamic to fixed allocation factors, the Company proposes a phased implementation of changes to its cost-allocation methodology. The Company began its Phase 1 implementation through the filing of the Washington 2026 Protocol on April 1, 2025.[3] The Washington 2026 Protocol provides for an immediate realignment of the Chehalis generating facility to become a situs resource to Washington, assigns Washington the unallocated share of Rolling Hills Wind, which the Public Utility Commission of Oregon previously disallowed, and incorporates a limited realignment of other resources to remove coal from Washington rates by January 1, 2026. The Washington 2026 Protocol also proposes to move from dynamic allocation factors (System Generation or SG) to fixed allocation factors (Fixed System Generation or SG-F), based on a four-year historical average of relevant load data, for all existing non-emitting and natural gas resources assigned to Washington (i.e., the Washington Fixed Portfolio).

As discussed in the direct testimony of Company witness Cindy A. Crane, the Company will propose a Phase 2 methodology to support its ability to meet upcoming legal obligations and enable different resource portfolios to comply with individual state or

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[3] *Washington Utilities and Transportation Commission v. PacifiCorp dba Pacific Power and Light Co.*, Docket No. UE-250224, Initial Filing (Apr. 1, 2025).

regional energy policy. For example, Utah Senate Bill ("SB") 224 (2024)[4] establishes a preference for dispatchable generation to serve Utah; House Bill ("HB") 411 (2019)[5] allows for Utah communities to opt-in to programs to reach 100 percent renewable generation by 2030; Oregon's HB 2021[6] and SB 1547[7] set resource and emissions targets starting in 2030; Washington SB 5116 (2019),[8] the Clean Energy Transformation Act, requires greenhouse gas neutrality by 2030 and carbon free retail electricity by 2045; and Washington HB 2528 (2020),[9] the Climate Commitment Act ("CCA"), requires the purchase of allowances for emissions from various sources in the state; Wyoming HB 200 (2020)[10] requires that a portion of load in the state to be served by carbon capture technology by July 1, 2033; and HB 166 (2021)[11] establishes a rebuttable presumption against coal or gas fueled plant retirement.

Q. Are there other important provisions proposed in the 2026 Protocol?

A. Yes. These include provisions addressing cost allocations for new large load customers. The costs caused by new large load customers (with an individual customer demand of over 50 megawatts) will be situs assigned when serving the new large load requires the Company to make investments or incur costs for assets placed in service after January 1, 2026. For these customers, the Company will work within the regulatory framework (i.e., a special contract or tariff) of that state to assign costs to the new large load customer.

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[4] UTAH CODE ANN. § 54-17-1001.
[5] UTAH CODE ANN. § 54-17-901 et. seq.
[6] OR. REV. STAT. §469A.400 et. seq.
[7] OR. REV. STAT. §757.518 et. seq.
[8] WASH. REV. CODE §19.405.010 et. seq.
[9] WASH. REV. CODE §70.45.005 et. seq.
[10] WYO. STAT. ANN. §37-18-102(a)(ii).
[11] WYO. STAT. ANN. §37-2-134.

Q. Please explain how your testimony is organized.

A. My testimony is organized to discuss:

- The history and development of the 2026 Protocol;
- A review of the standards the Commission has used in the past for reviewing cost-allocation methodologies; and
- An overview of the 2026 Protocol proposed for Utah in Phase 1 and its benefits to Utah energy policy objectives and customers.

Q. Are you also sponsoring any exhibits to your testimony?

A. Yes. Exhibit RMP____(RTL-1) presents the 2026 Protocol. Exhibit RMP____(RTL-2) presents the Washington 2026 Protocol.

IV. HISTORY AND DEVELOPMENT OF THE 2026 PROTOCOL

Q. Why is inter-jurisdictional cost allocation necessary for the Company?

A. As discussed in the testimony of Company witness Crane, the Company provides retail electric service to more than two million customers in the western states of Utah, California, Idaho, Oregon, Washington, and Wyoming. Importantly, the Company recovers the costs of providing retail electric service to customers through rates established in regulatory proceedings in each state. To ensure states receive the appropriate allocation of costs and benefits from the Company's integrated system, the Company has used the collaborative MSP to address allocation issues. This collaborative process has led to the development and adoption of a series of inter-jurisdictional cost-allocation methods over time.

Q. What cost-allocation method is the Company currently using in Utah?

A. The Company uses the 2020 Protocol in Utah. The Commission adopted and approved the 2020 Protocol in April 2020.[12]

Q. What is the 2020 Protocol?

A. The 2020 Protocol is an agreement between the Company and certain parties, including regulatory agency staff, consumer advocates, and other stakeholders in Utah, Washington, Idaho, Oregon, and Wyoming; the agreement also includes a state-specific Washington Inter-Jurisdictional Allocation Methodology ("WIJAM"). The parties to the 2020 Protocol agreed to support commission adoption and use of the 2020 Protocol in all Company rate proceedings filed after December 31, 2019, until the end of the "Interim Period" on December 31, 2023. The Utah,[13] Washington,[14] Idaho,[15] Oregon,[16] and Wyoming[17] commissions approved the 2020 Protocol in 2020, and the California Public Utilities Commission approved the 2020 Protocol in the Company's 2022 California general rate case.[18]

Q. What was the ultimate goal of the 2020 Protocol?

A. The 2020 Protocol initiated a fundamental shift to address inter-jurisdictional allocation factors with an ultimate goal to move away from dynamic allocation factors following the

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[12] *Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 19-035-42, Order Approving 2020 Protocol (Apr. 15, 2020).
[13] *Id.*
[14] *In the Matter of Washington Utilities and Transportation Commission v. PacifiCorp d/b/a Pacific Power and Light Company*, Docket Nos. UE-191024, et al., Final Order 09 / 07 / 12 (Dec. 14, 2020).
[15] *In the Matter of Rocky Mountain Power's Application for Approval of the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol*, Case No. PAC-E-19-20, Order No. 34640 (Apr. 22, 2020).
[16] *In the Matter of PacifiCorp, dba Pacific Power, Request to Initiate an Investigation of the Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket No. UM 1050, Order No. 20-024 (Jan. 23, 2020).
[17] *In the Matter of the Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 20000-572-EA-19 (Record No 15400), Order (Dec. 3, 2020).
[18] *In the Matter of the Application of PacifiCorp (U901E), for an Order Authorizing a General Rate Increase Effective January 1, 2023*, Application 22-05-006, Decision 23-12-016 (Dec. 14, 2023) (CPUC Decision 23-12-016).

Interim Period and move to a cost-allocation protocol with fixed allocation factors for generation resources and state-specific resource portfolios.

Q. Did the parties to the 2020 Protocol agree to extend the Interim Period and the duration of the 2020 Protocol?

A. Yes. In March 2023, the parties agreed to an amendment to the 2020 Protocol to extend the Interim Period and the duration of the 2020 Protocol until December 31, 2025. The commissions in Utah,[19] Oregon,[20] Idaho,[21] and Wyoming[22] approved the requested extension. Washington did not extend the WIJAM at that time because, by its terms, the WIJAM continues until it is replaced. California's approval the 2020 Protocol allowed for the use of that cost-allocation methodology until it is replaced in a future proceeding.

Q. Why did the parties seek to extend the Interim Period?

A. The 2020 Protocol defined certain unresolved issues as "Framework Issues." Before the extension, the parties (including Washington parties that were signatories to the 2020 Protocol) engaged in negotiations on the Framework Issues through the Framework Issues Workgroup. In those negotiations, the parties considered alternative resource-allocation methods (including the determination of states' fixed share of new resource acquisitions for future allocations), which they agreed warranted further review. The extension allowed the parties to continue discussions seeking to resolve the Framework Issues for a cost-allocation methodology for the post-Interim Period.

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[19] *In the Matter of the Application of Rocky Mountain Power for an Extension to the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 23-035-20, Order Approving Extension of the 2020 Protocol (July 27, 2023).
[20] *In the Matter of PacifiCorp, dba Pacific Power, Request to Initiate an Investigation of the Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket No. UM 1050, Order No. 23-229 (June 30, 2023).
[21] *In the Matter of Rocky Mountain Power's Petition for Approval of an Extension of the 2020 Inter-Jurisdictional Allocation Protocol*, Case No. PAC-E-23-13, Order No. 35984 (Nov. 2, 2023).
[22] *In the Matter of the Application of Rocky Mountain Power for Authority to Extend the 2020 Inter-Jurisdictional Cost Allocation Agreement Through December 31, 2025*, 20000-641-EA-23 (Record No. 17280), Order (Feb. 6, 2024)

Q. Why did the Commission ultimately agree to extend the 2020 Protocol?

A. The Commission approved the extension noting the complex and competing interests attendant to interjurisdictional cost-allocation and that over twenty different parties from five jurisdictions agreed to the extension.[23] The Commission acknowledged the tremendous amount of time and effort expended to resolve the allocation issues and recognized the overwhelming support for the 2020 Protocol and the extension.[24]

Q. Was the Framework Issues Workgroup able to reach consensus on the Framework Issues?

A. No. The Framework Issues Workgroup met for several years, but it was not able to reach consensus on a further extension of the 2020 Protocol or the terms of a replacement cost-allocation methodology by the end of the Interim Period. In July 2024, the Company informed its commissions that, given the circumstances, it would propose a new cost-allocation methodology by December 31, 2025, in accordance with Section 2.2.3 of the 2020 Protocol.[25]

Q. What are the principal challenges to the current cost-allocation methodology that the Company has tried to address through its proposed 2026 Protocol?

A. For decades, the Company has relied on cost-allocation methods that dynamically allocate total system costs to states. A foundational principle of these cost-allocation protocols has been the use of the Company's system as a single whole: except for distribution, all states were served from a common portfolio of assets, including generation assets, which enabled

[23] Docket No. 23-035-20 Order Approving Extension at 6.
[24] *Id.*
[25] Section 2.2.3 of the 2020 Protocol reads: "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."

the Company to cost effectively plan for and operate as an integrated whole, resulting in cost savings for all customers. However, divergent state policies across the Company's six-state service territory are increasingly challenging this foundational principle.

For example, Oregon SB 1547,[26] passed by the Oregon legislature in 2016, requires the elimination of coal from the electricity supplies to Oregon customers of the Company by 2030.[27] Oregon's requirement to remove coal from electricity supplies will necessarily result in Oregon not being allocated the costs and benefits of coal-fired generation while other states continue to include those resources in their electricity supply and in rates.

Divergent state policies have expanded since that time, with California,[28] Oregon,[29] and Washington[30] establishing zero emissions goals, Wyoming establishing a carbon capture technology goal[31] and standards for the evaluation of thermal retirement,[32] and Utah enacting the Community Renewable Energy Act[33] and establishing a preference for dispatchable generation.[34]

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[26] In 2016, the Oregon Legislature enacted SB 1547 that, among other things, increased the state's renewable portfolio standards (RPS) for electricity providers. The bill also requires the Commission to conduct an investigation and report to the Legislature on the impact of the increased RPS requirements on (1) rates; (2) greenhouse gas emissions; (3) electrical system reliability; (4) allocation of risk between electric utilities and their customers; (5) cost recovery for the generation of qualifying electricity; (6) resource procurement process; and (7) forecasting of and rate treatment of projected state and federal production tax credits. These requirements were first introduced in the Oregon Legislature as HB 4036 but were later moved into SB 1547.
[27] OR. REV. STAT. §757.518(2).
[28] CAL. PUB. UTIL. CODE §454.53.
[29] OR. REV. STAT. §469A.410(1)(c).
[30] WASH. REV. CODE §19.405 et seq.
[31] WYO. STAT. ANN §37-18-102.
[32] WYO. STAT. ANN §37-2-134.
[33] UTAH CODE ANN. §54-17-901.
[34] UTAH CODE ANN. §54-17-1001.

Q. How have the challenges of diverging state policies been addressed in the 2026 Protocol?

A. As stated by Ms. Crane, states' energy policies continue to develop and are being implemented in ways that make it increasingly difficult for the Company to operate and dispatch a single resource portfolio for all customers across all jurisdictions while meeting its legal obligations in each state. The 2026 Protocol defines a Five-State Portfolio of resources, which will continue to be dynamically allocated until the cost-allocation methodology transitions to fixed allocation factors planned for phase 2. Further, the 2026 Protocol proposes flexibility when allocating costs for new resources to allow for state autonomy when procuring new resources needed to achieve state-specific policy objectives.

Q. Has the Company already submitted filings to state regulatory bodies to implement a new cost-allocation methodology under Section 2.2.3 of the 2020 Protocol?

A. Yes. The Company filed the Washington 2026 Protocol with the Washington Utilities and Transportation Commission on April 1, 2025, in docket UE-250224. This proceeding is now pending, with a target decision date that permits implementation of the Washington 2026 Protocol by January 1, 2026.

Q. Does the Company seek approval of the 2026 Protocol under the same general timeframe as the Washington 2026 Protocol?

A. Yes, as much as possible, the Company hopes to keep all states in sync as resources are realigned under the 2026 Protocol and the Washington 2026 Protocol.

V. STANDARD FOR REVIEW OF THE 2026 PROTOCOL

Q. Is the Company seeking to replace the current cost-allocation methodology approved by the Commission in docket 19-035-42 and extended in docket 23-035-20?

A. Yes, the Company requests that the Commission approve the new cost-allocation methodology in the 2026 Protocol to supersede the current allocation methodology from the 2020 Protocol.

Q. Under which statutes does the Company apply to the Commission to adopt the updated inter-jurisdictional cost-allocation methodology?

A. The Company submits this application in accordance with Utah Code Ann. §§ 54-4-1, 54-4-21, and 54-4-23.

Q. The Company has presented previous cost-allocation methodologies as part of an agreement among most stakeholders, whereas the Company is seeking stakeholder consideration of its proposal in this case through the Commission's contested case process. What standard should the Commission apply to its review of the Company's filing?

A. In past cases, absent a settlement, the Commission has reviewed the proposed allocation methodology under U.C.A. § 54-3- 1, requiring that all utility charges must be just and reasonable because the allocation methodology will be used to establish rates in Utah.[35]

Q. Did the Company enter into a supplemental agreement with certain Utah parties related to the 2020 Protocol?

A. Yes. The Company signed a letter agreement with the Utah Division of Public Utilities, the Utah Office of Consumer Services, Utah Clean Energy, Western Resource Advocates,

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[35] *In the Matter of the Application of PacifiCorp for an Investigation of Inter Jurisdictional Issues*, Docket No. 02-035-04, Report and Order at 17 (Feb. 3, 2012).

Wolverine Fuels, and the Utah Association of Energy Users (collectively the "Utah Parties") related to the Interim Period resource reassignment filings under the 2020 Protocol.[36]

Q. Please describe the letter agreement.

A. Under Section 4.2 of the 2020 Protocol, after receipt of an exit order from one state, the Company must analyze whether it is reasonable to continue to operate the affected coal-fueled resource for customers in one or more of the states without exit orders. The Company may then propose reassignment of a greater share of the coal-fueled resource to such state(s) to match state load and resource balance, or request issuance of an exit order.

The letter agreement provided that at least 90 days prior to a reassignment filing with the Commission, or at least 30 days after an exit order from another state commission after October 1, 2020, the Company would convene at least one meeting with the identified Utah Parties to disclose and discuss any proposals for reassignment of interim period resources and the assumptions the Company plans to use in its analysis, as well as the rationale for those assumptions. The letter agreement further provided the timelines for filing for reassignment in accordance with the 2020 Protocol.

Q. Does the letter agreement apply to the 2026 Protocol?

A. No. The Company previously notified the Commission that the Company does not anticipate filing reassignment cases.[37] As discussed in its February 18, 2022 notice to the Commission, Section 4.2 was not implicated because: 1) the signatories to the 2020 Protocol were continuing to work towards resolution of the long-term planning and new

[36] *In the Matter of the Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 19-035-42, Exhibit RMP JLS-3 (filed Dec. 3, 2019).
[37] *In the Matter of the Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost-allocation Agreement*, Docket No. 19-035-42, Notice (Feb. 18, 2022).

resource assignment framework issue; 2) while the Public Utility Commission of Oregon approved some exit dates, it noted that it would continue to evaluate the economics of the Company's coal fleet; 3) the Company was in the middle of updating its modeling tools to better reflect the future allocation methodology envisioned in the 2020 Protocol; and 4) the Company was preparing its 2021 Integrated Resource Plan ("IRP") and the delay will allow for consistent assumptions in both the IRP and the reassignment analysis. On September 1, 2021, the Company filed its 2021 IRP, which indicated a common closure for the coal-fueled resources with exit orders prior to December 31, 2027.[38]

Consistent with Section 4.2.3 of the 2020 Protocol, if a regulatory proceeding results in the common closure dates of a coal-fueled resource then the process for common closure under Section 4.1.1 will apply. As a result, reassignment proceedings for those resources were no longer necessary.

Additionally, the letter agreement does not apply to the 2026 Protocol as the Company is not reassigning coal facilities under Section 4.2 of the 2020 Protocol.

VI. THE 2026 PROTOCOL

Q. What is the 2026 Protocol?

A. The 2026 Protocol describes the Company's allocation and assignment methodology and future transition to accommodate diverging resource[39] portfolios needed to address individual state energy policy. The 2026 Protocol is intended to: (1) supersede the 2020 Protocol for the Five States; and (2) operate in conjunction with the Washington 2026 Protocol. Subject to the provisions in the 2026 Protocol, once approved by the appropriate

[38] *PacifiCorp's 2021 Integrated Resource Plan*, Docket No. 21-035-09, 2021 Integrated Resource Plan, Volume I at 15 (Sept. 1, 2021).
[39] Resource includes both electric generation facilities and storage technology.

state bodies charged with issuing orders to establish rates, the 2026 Protocol can be used to set just and reasonable rates in rate filings in the Five States.

The 2026 Protocol implements components of the 2020 Protocol's post-interim methodology framework, modified to address the changing energy landscape. The 2026 Protocol realigns existing resources to enable dispatch of different resource portfolios to meet individual or regionally consistent state energy policy mandates and improve planning processes while providing the Company with the opportunity to recover its costs.

Q. How does the 2026 Protocol benefit Utah customers?

A. The 2026 Protocol benefits Utah customers by increasing Utah's ability to meet its future resource adequacy and energy needs while providing flexibility in the allocation of new resources needed to comply with Utah's and other state's energy policies. In this way, the 2026 Protocol better aligns with cost-causation principles as the Company seeks to comply with diverging state policies, whereby Utah customers will be responsible for costs that reflect Utah's specific needs.

Q. How will the 2026 Protocol impact revenue requirement in Utah?

A. The Company calculated the revenue requirement impact by comparing the allocation of generation resources using the 2020 Protocol compared to the 2026 Protocol. For Utah, the estimated revenue requirement increases by approximately \$23.5 million or 1.0 percent (\$8.2 million for net power costs ("NPC") and \$15.3 million for other costs). Company witness Shelley E. McCoy discusses the Company's calculation of the revenue requirement impact in more detail in her testimony, and Company witness Ramon J. Mitchell discusses the impact on NPC.

Q. How does the Company propose to track the cost-allocation differences from implementing the 2026 Protocol until the costs are reflected in rates?

A. The Company plans to file a deferral to track the cost-allocation differences from implementing the 2026 Protocol until these changes are reflected in rates.

Q. Please provide an overview of the sections of the 2026 Protocol.

A. The next section of my testimony will walk through the key provisions of Sections 1.0 through 15.0 of the 2026 Protocol.

<u>Section 1.0—Introduction</u>

Q. Does the 2026 Protocol provide an introduction and broader context for this filing?

A. Yes. The introduction summarizes the purpose and need for the 2026 Protocol including how it enables the Company to respond to several major changes in the energy landscape, and as discussed above, realignment of certain existing generation resources.

Q. Does the 2026 Protocol prejudge prudence or limit the Commission's responsibility to determine prudence and just and reasonable rates?

A. No. Section 1.0 of the 2026 Protocol makes clear that the proposed allocation of a particular expense or new investment to a state under the 2026 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.

Q. Will the 2026 Protocol abrogate any of the Commission's rights or obligations?

A. No. Nothing in the 2026 Protocol is intended to abrogate any commission's right or obligation to determine fair, just, and reasonable rates.

<u>Section 2.0—Effective Period and Phase 1 Implementation</u>

Q. What is the effective period of the 2026 Protocol?

A. Upon approval by the state commission in each jurisdiction, the 2026 Protocol will be effective for new regulatory rate filings in that jurisdiction beginning January 1, 2026, and will remain effective until superseded by a future amendment or new protocol approved by the state commissions.

Q. Does the Company propose implementing a new cost-allocation methodology in a single set of filings this year?

A. No. As discussed above, the Company proposes a phased approach for implementing its modified cost-allocation methodology. Phase 1 includes the recommended adoption of the Washington 2026 Protocol and the 2026 Protocol in the Five States. The Company will present a Phase 2 filing to the state regulatory commissions to be effective no later than 2030. Phase 2 will encompass additional elements, which may include: setting fixed allocations among the Five States; the implementation of a market settlement approach to NPC; the reallocation of costs for resources needed to comply with state laws that have binding compliance milestones beginning 2030; and the allocation of transmission costs.

Q. Why is it important to use a phased approach?

A. The scope of the 2026 Protocol primarily addresses the expiration of the 2020 Protocol, Washington's exit from coal, and state disallowance of carbon costs. Phase 2 will be significantly broader since it will address complex operational and planning issues. the Company needs additional time to develop a comprehensive proposal for Phase 2. Approval of the 2026 Protocol, which is a principled allocation methodology, is necessary to replace the 2020 Protocol while the allocation methodology in Phase 2 is developed.

Section 3.0—Allocation of Resources

Section 3.1 - Existing Resource Portfolios

Q. Please describe the allocation of existing resources under the 2026 Protocol.

A. There will be two portfolios of existing resources—the Five-State Portfolio and the Washington Fixed Portfolio. Resources in the Five-State Portfolio will be dynamically allocated. The Washington Fixed Portfolio is based on a fixed allocation or a situs assignment of certain resources, as reflected in the Washington 2026 Protocol.

There are four different subsets of resources in the two portfolios. The first subset of resources includes those that are allocated to both portfolios (the Five-State Portfolio and the Washington Fixed Portfolio). The second subset is for resources that are fully allocated to the Five-State Portfolio and not included in the Washington Fixed Portfolio. The third subset is for Rolling Hills Wind, which is included in the Five-State Portfolio, with the exception of Oregon, and in the Washington Fixed Portfolio. The fourth subset includes Washington situs-assigned resources that are fully allocated to the Washington Fixed Portfolio. The subsets of resources included in the two portfolios are summarized in the table below.

Plant Name/Resource Type	Five-State Portfolio (OR, CA, ID, UT, WY)	Washington Fixed Portfolio	Total
Resource Subset 1			
Jim Bridger 1 & 2	92.10%	7.90%	100%
Other Existing Non-Emitting Resources (non-QFs)	92.10%	7.90%	100%
Legacy Interruptible Contracts	92.10%	7.90%	100%
Resource Subset 2			
Other Natural Gas and Coal (non-QFs)	100%	0%	100%
Five State QFs	100%	0%	100%
Resource Subset 3			
Rolling Hills Wind (excluding OR)	65.13%	34.87%	100%
Resource Subset 4			
WA QFs	0%	100%	100%
Chehalis	0%	100%	100%

Section 3.2 - Dynamic Allocation of Five State Portfolio

Q. Please explain the Five-State Portfolio in more detail.

A. As discussed above, the Five-State Portfolio will be dynamically allocated for customers in Utah, California, Idaho, Oregon, and Wyoming. Non-fuel generation costs will be allocated using one of three different versions of a Five-State system generation factor (SG5). The three versions of the SG5 factor account for the different subsets of resources that are included in the Five-State Portfolio. For non-emitting resources (excluding Rolling Hills Wind and qualifying facilities or "QFs"), Jim Bridger Units 1 and 2, and legacy interruptible contracts, the Five States will be allocated costs using a dynamic generation factor excluding the fixed percentage allocated to Washington (SG5A). For all other thermal units, excluding Chehalis, and certain QFs, states will be allocated costs using a dynamic generation factor among the Five States (SG5B). For Rolling Hills Wind, states will be allocated costs using a dynamic generation factor among Utah, California, Idaho, and Wyoming excluding the fixed percentage allocated to Washington (SG5C).[40]

Resource Subset 1

Q. For resource subset 1, how does the Company propose to allocate the non-emitting resources (excluding Rolling Hills Wind and QFs), Jim Bridger Units 1 and 2, and legacy interruptible contract resources?

A. Under the SG5A factor, the non-emitting resources (excluding Rolling Hills Wind and QFs), Jim Bridger Units 1 and 2 natural gas facilities, and legacy interruptible contracts will be allocated dynamically to the Five States, while Washington will be allocated a fixed share of these resources.

Q. What is the SG5A factor for Utah?

A. While dynamic allocation means that the relative percentage used to serve customers in the Five States will vary on a year-to-year basis based on each state's relative load compared to the combined load of the Five States, the Company estimates approximately 44.9144 percent of the costs from these resources will be allocated to Utah customers in 2026.

Q. Why are the Jim Bridger 1 and 2 natural gas facilities included in resource subset 1?

A. With the conversion of Jim Bridger Units 1 and 2 from coal to natural gas, these resources provide capacity benefits to the entire system and can be managed to meet energy policies in all states to maintain reliability. Accordingly, these resources will be allocated to all states, similar to the non-emitting resources**.** This essentially maintains the *status quo* for these resources.

[40] Washington has been allocated the unallocated percentage of Rolling Hills that had been previously disallowed from Oregon rates in 2008. *See In the Matter of PacifiCorp d/b/a Pacific Power, 2009 Renewable Adjustment Clause*, Docket No. UE 200, Order No. 08-548 at 19-21 (Nov. 14, 2008).

Resource Subset 2

Q. What resources are in resource subset 2?

A. Resource subset 2 includes non-QF coal and natural gas resources (other than Chehalis and Jim Bridger 1 and 2) and certain QFs.

Q. How does the Company propose allocating these resources in the 2026 Protocol?

A. All of the costs associated with these resources will be allocated dynamically to the Five States using the SG5B allocation factor.

Q. Will Washington receive a fixed percentage of these resources?

A. No. These resources, with the exception of Hermiston, were either not previously included in Washington rates or must be removed to comply with Washington's Clean Energy Transformation Act. Hermiston is included to balance resource capacity given the realignment of Chehalis to address Washington CCA requirements.

Q. What QFs are included in this resource subset?

A. Legacy QF power purchase agreements ("PPAs"), which have previously been treated as system resources, are included in resource subset 2. As the legacy QF PPAs expire, should they be renewed they will be removed from this resource subset and treated as situs resources based on the state where the power is delivered to the Company's system under a QF PPA subject to that state commission's authority.

Q. What is the SG5B allocation factor for Utah?

A. While dynamic allocation means that the relative percentage used to serve customers in the Five States will vary on a year-to-year basis based on each state's relative load compared to the combined load of the Five States, the Company estimates approximately 48.7654 percent of the costs from these resources will be used to serve Utah customers in 2026.

Resource Subset 3

Q. What resources are in resource subset 3?

A. Resource subset 3 includes Rolling Hills Wind.

Q. What is Rolling Hills Wind?

A. Rolling Hills Wind is a 100 megawatt wind project sited at the reclaimed Dave Johnston coal mine in Wyoming. The facility began operations in 2009, and the Company completed a repowering project at Rolling Hills in 2019.

Q. Under the 2026 Protocol, will any generation from Rolling Hills Wind be allocated to Utah?

A. Yes. Utah customers will receive a dynamically allocated share of Rolling Hills equal to Utah's current allocation. In 2008, the Public Utility Commission of Oregon disallowed recovery of Rolling Hills Wind costs and excluded it from Oregon rates.[41] As a result, approximately 26 percent of Rolling Hills Wind costs and benefits are not currently allocated to any state. The Company proposes to allocate the unallocated portion of Rolling Hills Wind to Washington, increasing Washington's share of Rolling Hills Wind from 7.8971 percent to 34.8727 percent. The remainder of Rolling Hills Wind will be dynamically allocated to Utah, California, Idaho, and Wyoming.

Resource Subset 4

Q. What resources are in resource subset 4?

A. Resource subset 4 includes Washington QFs and Chehalis.

Q. Are any of these resources allocated to Utah under the 2026 Protocol?

A. No.

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[41] *In the Matter of PacifiCorp, dba Pacific Power 2009 Renewable Adjustment Clause Schedule 202*, Docket No. UE 200, Order No. 08-548 at 20 (Nov. 14, 2008).

Q. Does situs assignment of Chehalis to Washington impact NPC costs in Utah?

A. As discussed in the testimony of Mr. Mitchell, not taking into account costs related to compliance with the Washington CCA, the total-Company NPC increase for the Five States is estimated to be approximately $15.9 million.[42] For Utah specifically, the initial NPC impact calculation without Washington shows an approximate NPC increase of $8.2 million, or 0.73 percent.[43]

Importantly, however, Washington CCA costs for 2026 are forecasted to be approximately $54.9 million on a total-company basis.[44] Once Chehalis is situs assigned to Washington, the obligation to pay these costs (an obligation that is now subject to litigation in many states) is removed from the Five States. If Washington CCA costs were factored into the Company's analysis, NPC *decreases* by approximately $26.8 million in the Five States under the 2026 Protocol, or by $16.4 million, or 1.42 percent, on a Utah-allocated basis.[45]

Section 3.3 - Legacy Interruptible Contracts

Q. How does the Company propose to allocate the costs for legacy interruptible contracts under the 2026 Protocol?

A. Under the 2026 Protocol, the Company proposes to allocate the costs for legacy interruptible contracts using the SG5A factor. This is consistent with current practice and reflects the benefits provided by these contracts to all states.

[42] *See* Direct Testimony of Ramon J. Mitchell at 10-11 (Aug. 5, 2025).
[43] *Id.*
[44] *See Id.* at 11.
[45] *Id.* at 11.

Q. How are benefits provided by these contracts?

A. Interruptible industrial loads provide benefits across all states because they provide the ability to coordinate the rapid reduction of large increments of load in response to system or interconnection-wide events. This can produce benefits for all customers by reducing the impact of high market prices.

Section 3.4 - Qualifying Facilities

Q. How does the Company propose to allocate costs of QF PPAs?

A. The costs, any corresponding renewable energy certificates ("RECs"), as applicable, and all environmental attributes of QF PPAs are allocated based on when the PPA was fully executed—on or before December 31, 2019, or after 2020.

Q. How are the costs and benefits for QF PPAs executed on or before December 31, 2019, allocated?

A. As mentioned above in the discussion of resource subset 2, the costs, any corresponding RECs, as applicable, and all environmental attributes of the QF PPAs fully executed on or before December 31, 2019[46] will be allocated using the SG5B factor.

Q. What about the costs for QF PPAs executed after December 31, 2019?

A. The costs of QF PPAs fully executed or as to which a legally enforceable obligation existed after December 31, 2019, will be dynamically allocated with the SG5B factor, up to the level of cost that is based on a forecasted reasonable energy price. Any costs of a QF PPA above the forecasted reasonable energy price will be situs assigned and allocated to the state of origin. The corresponding RECs, as applicable, and all environmental attributes from the post-2020 QF PPAs will also be situs assigned to the state of origin.

[46] This includes all QF PPAs that were system allocated under the 2020 Protocol.

Q. What is the forecasted reasonable energy price?

A. The forecasted reasonable energy price is a single blended market price derived from the Company's official forward price curve, scaled for hourly prices. The calculation for this single blended market price is discussed in Section 3.4.1 of the 2026 Protocol.

Q. Does the 2026 Protocol propose any other notable deadlines regarding changes to the allocation of costs and benefits for QF PPAs?

A. Yes. No later than January 1, 2030, the costs and all environmental attributes for QF PPAs will be situs assigned to the state of origin regardless of when the QF PPA was executed.

Section 3.5 - Demand Side Management

Q. Does the 2026 Protocol change how demand-side management program costs are allocated from the 2020 Protocol?

A. No. Costs associated with demand-side management programs will continue to be directly allocated to the state in which the investment is made (i.e., situs assigned). 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.

Section 3.6 - Allocation of New Resources

Q. How are new resources defined under the 2026 Protocol?

A. New resources are any non-QF generating facility procured after April 1, 2025. In this context, a resource is "procured" when a generation or resource contract is effective.

Q. How does the Company plan to allocate costs and benefits for new generation resources?

A. The Company will propose an allocation for new resources with a term or depreciable life longer than three years at or before the time when a prudence review occurs. New resources with a term or depreciable life less than three years will be allocated in accordance with the NPC calculation under Section 4.0 of the 2026 Protocol, discussed below.

Section 3.7 - State-Imposed Costs

Q. What are state-imposed costs?

A. State-imposed costs include, but are not limited to, taxes, fees, and costs for environmental permitting imposed on a generation resource or associated assets.

Q. How does the 2026 Protocol address state-imposed costs?

A. Under the 2026 Protocol, state-imposed costs are generally allocated consistent with the allocation of the resource under the Five-State Portfolio.

Q. What about costs and revenues related to a state greenhouse gas pricing program?

A. If a state imposes a carbon or greenhouse gas pricing program (for example, a cap-and-trade program or a carbon tax) on a resource, all costs and revenues associated with that program will be situs assigned to the state imposing that obligation. If the state imposing a carbon or greenhouse gas pricing program is not a jurisdiction with Company retail customers, or if the costs are imposed by the federal government, then the costs will be allocated consistent with the Five-State Portfolio.

Q. How does the 2026 Protocol allocate the costs and revenues for other state programs and initiatives?

A. Under the 2026 Protocol, costs and revenues will be situs assigned when they are incurred to comply with a program or initiative imposed by a particular state on the Company in its role as a public utility serving customers in that state. This includes portfolio standards, customer generation programs, emissions performance standards, voluntary renewable energy programs, capacity standard programs, electric vehicle programs, and the acquisition of RECs.

Section 3.8 - Allocation of Decommissioning and Closure Costs

Q. How does the 2026 Protocol allocate costs at plant closure?

A. Upon closure of a resource before 2030, any remaining rate base and associated expense, including decommissioning costs, will be allocated consistent with the dynamic allocation of the resource as part of the Five-State Portfolio. For resources with a closure date of 2030 or later, the Company will propose a methodology for the treatment of closure and decommissioning costs in Phase 2 of the 2026 Protocol.

Section 3.9 - Capital Additions to Coal-Fired Resources Before 2030

Q. How will the Company allocate costs associated capital additions made before 2030?

A. To facilitate removal of coal generation from Oregon rates in compliance with the requirements of Oregon SB 1547, Oregon customers will be allocated a time-based *pro rata* share of the costs for capital additions to coal-fired resources made before 2030. The pro rata share would be based on the number of months left in the Oregon depreciable life of the resource compared to the number of months left in the longest depreciable life of the resources used in Utah, California, Idaho, or Wyoming. That ratio would then be applied to the SB5B factor share of the investment. Costs associated with any such capital additions will be dynamically reallocated to the remaining states following Oregon's exit from the resource.

<u>Section 4.0—Allocation of Net Power Costs</u>

Q. How is NPC allocated in the 2026 Protocol?

A. For actual NPC filings, the Company will use the allocation methodology in place when the NPC was or will be incurred, to align the timing of the actual costs incurred with the applicable allocation method for cost recovery for that period. Before the implementation of Phase 2, NPC will continue to be dynamically allocated consistently with the allocation factors identified in the 2026 Protocol. For NPC filings, the allocation methodology that will be used will be based upon the table below.

Annual Actual NPC Filing	Filed	Year in Review	Base NPC	Actual NPC
EBA	2026	2025	2020 Protocol	2020 Protocol
EBA	2027	2026	2020 Protocol	2026 Protocol

Q. What factors will be used to allocate NPC?

A. NPC will be allocated consistent with the allocation factors identified for the appropriate FERC account in Appendix B of the 2026 Protocol. States will also receive an allocation of the costs or revenues resulting from the valuation of the difference between the Five-State Portfolio's load and allocated resources using a dynamic SG5B factor, as described in more detail by Mr. Mitchell. Situs generation resources will continue to use the lower of cost or market methodology, which is also further explained by Mr. Mitchell.

Q. Does the Company anticipate changing its methodology for allocating NPC?

A. Yes. In Phase 2, as the Company moves to fixed allocation factors, the Company proposes implementing a market settlement-based NPC allocation methodology to ensure that NPC can be allocated at a more granular level to meet state-specific portfolios. Company witness Michael G. Wilding discusses the Company's transition to nodal pricing, including the nodal pricing methodology, for NPC in greater detail in his testimony. A nodal-pricing regime will allow states to pursue portfolios while maintaining the benefits of system dispatch as much as practicable.

<u>Section 5.0.—Transmission Costs</u>

Q. How has the allocation of system transmission costs changed under the 2026 Protocol?

A. As is done in the 2020 Protocol, the Company proposes that all existing system transmission costs continue to be dynamically allocated among the Five States and

Washington using the SG factor. This allocation may be subject to additional review and amendment in Phase 2. The only exception to this methodology applies to new large loads, which is discussed in Section 13.0 of the 2026 Protocol.

Q. What percentage of system transmission does the Company propose allocating to Utah customers?

A. The SG factor would result in allocating approximately 45.1209 percent of system transmission costs to Utah customers, which will vary on a year-to-year basis based on each state's relative load compared to the combined load. But for the exception pertaining to new large loads, this is unchanged from the allocation under 2020 Protocol and therefore is rate neutral.

<u>Section 6.0—Allocation of Distribution Costs</u>

Q. Does the Company propose changing the allocation of distribution-related expenses and capital costs under the 2026 Protocol?

A. No. All distribution-related expenses and capital costs that can be directly allocated will be directly allocated (100 percent) to the states where the related distribution facilities are located.

<u>Section 7.0—Allocation of System Overhead Costs</u>

Q. Does the Company propose changing the allocation of system overhead ("SO") expenses under the 2026 Protocol?

A. While the Company proposes to continue to allocate costs that support more than one function, such as generation, transmission, or distribution plant on the SO factor, the calculation of the factor is updated to be based on an equal one-third weighting of the system capacity ("SC") factor, system energy ("SE") factor, and system gross plant distribution ("SGPD") factor as shown in Appendix C to the 2026 Protocol. This change in the allocation calculation is necessary to reflect the fixed allocations of resources between the Washington Fixed Portfolio and Five-State Portfolio and is explained in more detail by Ms. McCoy.

<u>Section 8.0—Allocation of Taxes and Fees</u>

Q. What has the Company changed about the allocation of taxes and fees?

A. The treatment and allocation of taxes and fees continue to remain largely the same as was approved in the 2020 Protocol. Idaho has recently replaced its property tax with a newly enacted Kilowatt Hour tax. For purposes of the 2026 Protocol, this will continue to be considered and allocated similar to the previous Idaho property tax. No other revisions to the allocation of taxes or fees are included in the 2026 Protocol. Ms. McCoy discusses the allocation of taxes and fees more thoroughly in her direct testimony.

<u>Section 9.0—Allocation of Administrative and General Costs</u>

Q. Does the Company propose changing how administrative and general costs are allocated in the 2026 protocol?

A. Yes. 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. Those costs that cannot be directly allocated will be allocated among all states consistent with the factors set forth in Appendix B as they were in the 2020 Protocol.

<u>Section 10.0—Treatment of Oregon Direct Access Programs</u>

Q. Under the 2026 Protocol, does the Company propose any changes to how it currently addresses loads lost to Oregon Direct Access Programs?

A. No, the Company does not propose any changes to its current treatment of loads lost to Oregon Direct Access Programs.

Section 11.0—Loss or Increase in Load

Q. Is there any change in how the 2026 Protocol treats loss or increase in load from the 2020 Protocol?

A. No.

Section 12.0—Excess Liability Insurance and Liability Allocation

Q. How will the costs for non-wildfire-related insurance premiums for excess liability and costs for non-wildfire liability be allocated among the states?

A. The costs for non-wildfire-related insurance premiums for excess liability and costs for non-wildfire liability not covered by insurance will be allocated among the states using the SO factor. The costs for any wildfire-related insurance coverage for generation and transmission assets in states where the Company does not have retail customers will be allocated using the SO factor as well. The costs for wildfire-related insurance coverage and liability in retail states will be addressed on a state-by-state basis.

Q. Why is the Company proposing to address wildfire-related insurance coverage and liability on a state-by-state basis?

A. The Company's expansive system covers a diverse range of climate and vegetation zones, serving a combination of sparsely populated rural and densely populated urban areas, meaning that wildfire risk is not identical across the system. Moreover, state policies regarding wildfire liability for electric utilities continue to evolve. The Company is currently engaging with stakeholders on the appropriate treatment of wildfire-related insurance coverage and liability for its retail service states and is exploring options beyond standard third-party insurance.

<u>Section 13.0—Allocation of New Large Load</u>

Q. How does the 2026 Protocol address New Large Load customers?

A. The costs of New Large Load over 50 megawatts that require the Company to make investments or incur costs for assets placed in service after January 1, 2026, will be assigned to the state in which the load is located. The Company will work within potential regulatory frameworks available in Utah (i.e., a special contract or tariff) to assign the costs to the New Large Load customer, as determined by the Commission. These costs include, but are not limited to, any new distribution costs, transmission costs, generation costs (including power purchase agreements, as applicable), and contractual costs for providing electrical service (i.e., firm third-party transmission rights).

<u>Section 14.0—Allocation of Gain or Loss from Sale of Assets</u>

Q. How does the 2026 Protocol address the allocation of gains or losses from the sale of assets?

A. Section 14.0 provides that the allocation of any gains or losses from the sale of Company-owned assets will be based on the assignment of the asset at the time of the sale, unless the asset has been under that assignment less than a calendar year from the execution date of the sale agreement, in which case any gains or losses would be allocated based on the prior assignment shares. This provision is unchanged from the 2020 Protocol.

<u>Section 15.0—Interpretation and Governance</u>

Q. Please explain Section 15.0 of the 2026 Protocol.

A. Section 15.0 of the 2026 Protocol provides details regarding the interdependence of commission approvals, establishing that any approval by a given commission is contingent upon the 2026 Protocol being approved unaltered by other commissions. In addition, to the extent that an issue of interpretation causes an allocation difference between multiple jurisdictions, Section 15.0 describes the Company's ability to petition state commissions to amend the 2026 Protocol and resolve any allocation discrepancies.

VII. RECOMMENDATION

Q. What action do you recommend the Commission take with respect to the Company's Application?

A. I recommend that the Commission approve the 2026 Protocol, based on a finding that there is good cause for the Company's 2026 Protocol, that the 2026 Protocol allows the Company an opportunity to recover its prudently incurred costs, ensures that Utah's share of costs is equitable among the states subject to the 2026 Protocol, and is reasonable and in the public interest.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick T. Link

2026 PacifiCorp Inter-Jurisdictional Allocation Protocol

August 2025

2026 PacifiCorp Inter-Jurisdictional Allocation Protocol

Contents

1.0 Introduction

The 2026 PacifiCorp Inter-Jurisdictional Allocation Protocol (the "2026 Protocol") describes PacifiCorp's cost allocation and assignment methodology to take effect on January 1, 2026, subject to Commission approvals. The 2026 Protocol is the first phase in a multi-phase process to transition PacifiCorp's cost-allocation methodology to accommodate diverging resource portfolios and changes to operations needed to address individual state energy policies. The 2026 Protocol is intended to: (1) supersede the 2020 Protocol[1] in the Five States; and (2) operate in conjunction with the Washington 2026 Protocol. Subject to the provisions set forth below, once approved by Commissions, the 2026 Protocol can be used to set just and reasonable rates in rate filings in the Five States. The 2026 Protocol describes a cost-allocation methodology, which, if used by all Five States for rate proceedings filed with rates effective beginning January 1, 2026, will align costs and benefits for customers and afford PacifiCorp a reasonable opportunity to recover all of its prudently incurred expenses and investments and earn its authorized rate of return.

The Five States are implementing energy policies that make it increasingly difficult for PacifiCorp to operate and maintain a single resource portfolio for customers across all jurisdictions while meeting its legal obligations in each state. The 2026 Protocol implements a transition from a cost-allocation methodology that is consistent with the operation of a single resource portfolio to a cost-allocation methodology that is consistent with state or regional resource portfolios needed to meet load obligations on a least-cost basis, while complying with state energy policies and preventing cross-subsidization among jurisdictions. In addition, full allocation of all prudently incurred resources maximizes state benefits and supports the financial health of PacifiCorp. The 2026 Protocol marks an initial step to transition the allocation of costs to align with changes in

[1] Capitalized terms in the 2026 Protocol are defined herein or in Appendix A.

operations and to establish rate base in a manner that aligns costs and benefits consistent with state energy policies. The transition will be facilitated by participation in the Extended Day Ahead Market where market settlements can be used to allocate Net Power Costs associated with the Resource portfolio allocated to each state. This first phase of the transition is being implemented in the 2026 Protocol, which realigns existing Resources to allocate costs based on near-term state energy policy and legal obligations ("Phase 1"). This includes specific energy policy decisions made around the Chehalis natural gas facility ("Chehalis"), and all other thermal generation facilities. Additionally, the 2026 Protocol maintains a roughly similar resource adequacy position for each jurisdiction when compared against the 2020 Protocol. The 2026 Protocol provides a path for a second phase of a cost allocation transition that will support PacifiCorp's ability to meet upcoming legal obligations and enable different resource portfolios to comply with individual state or regional energy policy mandates ("Phase 2"). For example, Oregon's House Bill ("HB") 2021[2] and Senate Bill ("SB") 1547[3] set resource and emissions targets starting in 2030; Utah SB 224[4] establishes a preference for dispatchable generation; Utah HB 411[5] allows for Utah communities to opt-in to programs to reach 100 percent renewable generation by 2030; Washington SB 5116,[6] the Clean Energy Transformation Act, requires greenhouse gas neutrality by 2030 and carbon free retail electricity by 2045; Washington HB 2528,[7] the Climate Commitment Act, requires the purchase of allowances for emissions from various sources in the state; and Wyoming HB 200 requires a portion of load in the state to be served by carbon capture technology by July 1, 2033.[8]

[2] ORS §469A.400 et. seq.
[3] ORS §757.518 et. seq.
[4] UTAH CODE ANN. § 54-17-1001.
[5] UTAH CODE ANN. § 54-17-901 et. seq.
[6] WASH. REV. CODE §19.405.010 et seq.
[7] WASH. REV. CODE §70.45.005 et. seq.
[8] WYO. STAT. §37-18-102(a)(ii).

The proposed allocation of a particular expense or new investment to a state under the 2026 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 2026 Protocol is intended to abrogate any Commission's right or obligation to determine fair, just, and reasonable rates.

2.0 Effective Period and Phase 1 Implementation

The 2026 Protocol aligns costs and benefits for customers within the requirements of their state energy policies. It makes the changes necessary to realign the system to reflect the existing legal obligations and resource constraints that take effect January 1, 2026. Moving forward, PacifiCorp will present a Phase 2 filing to the Commissions to be effective no later than 2030, and it will encompass additional elements, which may include: setting fixed allocations among the Five States; the implementation of a market settlement approach to Net Power Costs;[9] the reallocation of Resources to comply with state laws that have binding compliance milestones beginning 2030; and the allocation of transmission assets.

Upon approval by the Commission in each jurisdiction, the 2026 Protocol will be effective for new regulatory filings in that jurisdiction beginning January 1, 2026, and will remain effective until superseded by a future amendment or new protocol approved by the Commission.

Phase 1 implementation provides for an immediate realignment of Chehalis to become a Situs resource to Washington and incorporates a limited realignment of Resources to remove coal from Washington rates by January 1, 2026. PacifiCorp will file for deferred accounting to track the costs and benefits from Phase 1. Once the 2026 Protocol is approved in a jurisdiction, the

[9] PacifiCorp may propose to move to a market settlement approach for NPC before Phase 2.

revised cost allocation factors will be implemented through rate proceedings initiated after such approval.[10]

3.0 Allocation of Resources

3.1 Existing Resource Portfolios

There will be two portfolios of existing Resources—the Five State portfolio and the Washington fixed portfolio. The Five State portfolio is for customers in the Five States, and Resources in this portfolio will be dynamically allocated among those states. The Washington fixed portfolio includes a fixed allocation or Situs assignment of certain Resources, as reflected in the Washington 2026 Protocol.

There are four different subsets of Resources in the two portfolios. The first subset of Resources includes those that are allocated to both portfolios (the Five State portfolio and the Washington fixed portfolio). The second subset is for Resources that are fully allocated to the Five State portfolio and not included in the Washington fixed portfolio. The third subset is for Rolling Hills Wind, which is included in the Five State portfolio, with the exception of Oregon, and in the Washington fixed portfolio. The fourth subset includes Washington Situs Resources that are fully allocated to the Washington fixed portfolio. The subsets of Resources included in the two portfolios are summarized in the table below.

[10] The Washington 2026 Protocol was proposed in Washington through a power-cost only rate case filed in April 2025. *See In the Matter of Washington Utilities and Transportation Commission v. PacifiCorp d/b/a Pacific Power and Light Co.*, Docket No. UE-250224, Initial Filing (Apr. 1, 2025).

Plant Name/Resource Type	Five State Portfolio (OR, CA, ID, UT, WY)	Washington Fixed Portfolio	Total
Resource Subset 1			
Jim Bridger Units 1 & 2	92.10%	7.90%	100%
Other Existing Non-Emitting Resources (non-QFs)	92.10%	7.90%	100%
Legacy Interruptible Contracts	92.10%	7.90%	100%
Resource Subset 2			
Other Natural Gas and Coal (non-QFs)	100%	0%	100%
Five State QFs	100%	0%	100%
Resource Subset 3			
Rolling Hills Wind (excluding OR)	65.13%	34.87%	100%
Resource Subset 4			
WA QFs	0%	100%	100%
Chehalis	0%	100%	100%

3.2 Dynamic Allocation of the Five State Portfolio

The Five State portfolio will be dynamically allocated for customers in the Five States. Non-fuel generation costs will be allocated using one of three different versions of a Five State system generation factor ("SG5"). The allocation of fuel cost and other variable costs are discussed in Section 4 and identified in Appendix B. The three versions of the SG5 factor account for the different subsets of Resources that are included in the Five State portfolio. For non-emitting Resources (excluding Rolling Hills Wind and QFs), Jim Bridger Units 1 and 2, and Legacy Interruptible Contracts, costs will be allocated to the Five States using a dynamic generation factor excluding the fixed percentage allocated to Washington ("SG5A"). For all other thermal units, excluding Chehalis, and certain QFs, costs will be allocated using a dynamic generation factor ("SG5B") to the Five States. For Rolling Hills Wind, costs will be allocated using a dynamic generation factor among California, Idaho, Utah, and Wyoming excluding the fixed percentage allocated to Washington ("SG5C").[11] Additional information pertaining to the allocation of Legacy Interruptible Contracts and QFs is addressed in Sections 3.3 and 3.4, respectively.

Plant Name/Resource Type	Five State Dynamic Allocation Factors
Resource Subset 1	
Jim Bridger Units 1 & 2	SG5A
Other Existing Non-Emitting Resources (non-QFs)	SG5A
Legacy Interruptible Contracts	SG5A
Resource Subset 2	
Other Natural Gas and Coal (non-QFs)	SG5B
Five States' QFs pre-2020	SG5B (Situs Starting 2030)
Five States' QFs post-2020	Situs
Resource Subset 3	
Rolling Hills Wind	SG5C

3.3 Legacy Interruptible Contracts

The costs incurred for certain interruptible industrial load contracts (identified in Appendix D as Legacy Interruptible Contracts) will be allocated using the SG5A Factor. Revenues associated with these Legacy Interruptible Contracts will be included in state revenues, and loads of the associated interruptible contract customers will be included in dynamic allocation factors as appropriate (see Appendix D).

3.4 Qualifying Facilities

The costs, any corresponding Renewable Energy Certificate ("RECs"), and all environmental attributes of Five States' QF power purchase agreements ("PPAs") are allocated based on when the QF PPA was fully executed as outlined in this section. No later than January 1, 2030, all of the Five States' QF PPA costs, and all environmental attributes will be Situs assigned to the state of origin.

[11] Under the Washington 2026 Protocol, Washington will be allocated the unallocated percentage of Rolling Hills Wind that had been previously disallowed from Oregon rates in 2008. *See In the Matter of PacifiCorp d/b/a Pacific Power, 2009 Renewable Adjustment Clause*, Docket No. UE 200, Order No. 08-548 at 19-21 (Nov. 14, 2008).

The costs, any corresponding RECs, and all environmental attributes of the Five States' QF PPAs fully executed on or before December 31, 2019[12] will be allocated using the SG5B allocation factor.

The costs of post-2020 QF PPAs will be dynamically allocated using the SG5B factor, priced at a forecasted reasonable energy price outlined in Section 3.4.1, and any cost of a post-2020 QF PPA above the forecasted reasonable energy price will be Situs assigned and allocated to the state of origin. The corresponding RECs and all environmental attributes of post-2020 QF PPAs will be Situs assigned to the state of origin.

3.4.1 Forecasted Reasonable Energy Price

The forecasted reasonable energy price is a single blended market price derived from PacifiCorp's official forward price curve, scaled for hourly prices, that will be used for setting QF pricing for any Post 2020 QF PPAs. The single blended market price is calculated by applying the appropriate weighting to the hourly scaled prices from the official forward price curve for each market hub. The weightings per market hub are identified in the table below.

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%

[12] This includes all QF PPAs that were system allocated under the 2020 Protocol.

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.

3.5 Demand-Side Management

Costs incurred for Demand-Side Management Programs will be allocated on a Situs basis to the state in which the investment is made. Reduced consumption and contribution to coincident peak, will be reflected in the dynamic allocation factors.

3.6 Allocation of New Resources

PacifiCorp will propose an allocation factor for new Resources with a term or depreciable life longer than three years at or before a prudence review occurs. New Resources with a term or depreciable life less than three years will be allocated in accordance with Section 4. New Resources are any non-QF generating facility procured after April 1, 2025.[13]

3.7 State-Imposed Costs

Costs imposed by state law on a Resource, such as taxes, fees, and environmental permitting will be allocated consistent with the allocation of the Resource under Section 3.2 unless specifically identified in this section. If a state imposes a carbon or greenhouse gas pricing program (e.g., a cap-and-trade program or a carbon tax) on a Resource, the costs and revenues associated with that program will be Situs assigned to the state imposing that obligation. If the state imposing a carbon or greenhouse gas pricing program is not a jurisdiction with PacifiCorp retail customers, or if the costs are imposed by the federal government, then the costs will be allocated consistent with Section 3.2.

[13] For the purposes of this section, a Resource is procured when the contract procuring generation (PPA, asset purchase agreement, build transfer agreement, etc.) is effective.

Costs and revenues will be Situs assigned when they are incurred to comply with a program or initiative imposed by a particular state on PacifiCorp in its role as a public utility serving customers in that state. This includes Portfolio Standards, customer generation programs, emissions performance standards, voluntary renewable energy programs, capacity standard programs, electric vehicle programs, and the acquisition of RECs.

3.8 Decommissioning and Closure Costs

Upon Closure of a Resource, any remaining rate base and associated expense will be allocated consistent with Section 3.2. For Resources with a Closure date before 2030, Decommissioning Costs will be allocated based on the allocation factors identified in Section 3.2. For Resources with a Closure date of 2030 or later, PacifiCorp will propose a methodology in Phase 2.

3.9 Capital Additions—Coal Resources with Operational Lives Beyond 2030

To facilitate the removal of coal generation from Oregon rates, capital additions on coal-fired Resources made before December 31, 2029, will be allocated to Oregon on a time-based pro rata share until December 31, 2029. The cost of capital additions on coal-fired Resources made before 2030 will be dynamically reallocated to the remaining Five States. Oregon's pro rata share will be based on the number of months left in Oregon's depreciable life of the Resource compared to the number of months left in the longest depreciable life of the Resource used in the remaining Five States. For example, if a $100,000 investment is made at a plant where 15 months remain in Oregon's depreciable life and 123 months remain in the longest depreciable life for that plant in the remaining Five States, the following is the calculation for Oregon's pro rata share of the investment.[14]

[14] The percentages and amounts identified in the example below are used for illustrative purposes and may not reflect the actual dynamic allocation factors.

(Oregon Life in months / Total Remaining Life in months) x Investment x Oregon SG5B Factor, or, in the example above:

(15 months / 123 months) x $100,000 x 28.27% = $3,448

The remainder of the investment will be proportionately allocated to the remaining Five States , resulting in the cost allocation shown in the table below.

California	Oregon	Washington	Utah	Idaho	Wyoming	Total
1.92%	3.45%	0.00%	65.67%	8.79%	20.17%	100.00%
$1,923	$3,448	$0	$65,672	$8,792	$20,165	$100,000

4.0 Allocation of Net Power Costs

The table below summarizes the transition from the 2020 Protocol to the 2026 Protocol for Net Power Cost filings. Before implementation of Phase 2, Net Power Costs will continue to be dynamically allocated consistent with the allocation factors identified in this 2026 Protocol. For Net Power Cost filings, the allocation methodology that will be used will be based upon the table identified below.

	2020 Protocol				2026 Protocol			
Annual NPC Filings	Filed	Year in Review	Base NPC	Actual NPC	Filed	Year in Review	Base NPC	Actual NPC
OR PCAM	2026	2025	2020 Protocol	2020 Protocol	2027	2026	2020 Protocol	2026 Protocol
UT EBA	2026	2025	2020 Protocol	2020 Protocol	2027	2026	2020 Protocol	2026 Protocol
WY ECAM	2026	2025	2020 Protocol	2020 Protocol	2027	2026	2020 Protocol	2026 Protocol
ID ECAM	2026	2025	2020 Protocol	2020 Protocol	2027	2026	2020 Protocol	2026 Protocol
WA PCAM	2026	2025	2020 Protocol	2020 Protocol	2027	2026	2026 Protocol	2026 Protocol
CA ECAC Balancing	2026	2025	2020 Protocol	2020 Protocol	2027	2026	2020 Protocol	2020 Protocol

Net Power Costs will be allocated consistent with the allocation factors identified for the appropriate FERC Account in Appendix B. Each of the Five States will also receive an allocation of the costs or revenues resulting from the valuation of the difference between the Five-State portfolio's load and allocated Resources using a dynamic SG5B factor. Specifically, at the monthly granularity, the difference between: (1) the aggregate Five State portfolio's generation and market purchases; less (2) the aggregate Five State portfolio's load and market sales, will be valued at the monthly average short-term firm market transaction price. The average short-term firm market transaction price is the sum of all short-term firm transactions in dollars divided by the sum of all short-term firm transactions in megawatt-hours. PacifiCorp may propose to revise or integrate a market settlements-based methodology into the allocations of Net Power Costs. Situs Resources will continue to use the lower of cost or market methodology.[15]

5.0 Allocation of Transmission Costs

The costs associated with transmission assets will be dynamically allocated among the Five States and Washington using the system generation ("SG") factor, 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 SG factor. FERC Account 565 wheeling expenses will be allocated according to Appendix B. The 2026 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. Nothing in this section is intended to prevent PacifiCorp from using an alternative allocation of transmission costs for New Large Load customers as described in Section 13.0.

6.0 Allocation of 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 the states on a system net plant distribution ("SNPD") factor, as shown in Appendix C.

[15] This method compares the actual cost of a resource (such as a PPA) to the prevailing market price for electricity. The lower of the two values is used to allocate costs to states that do not have Situs responsibility for the resource. The state to which the resource is Situs assigned pays the difference between: (1) the actual cost of the resource; and (2) the total amount recovered from the other states. This method is unchanged from the 2020 Protocol.

7.0 Allocation of 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 but will be calculated based on an equal one-third weighting of the system capacity ("SC") factor, system energy ("SE") factor, and system gross plant distribution ("SGPD") factor, as shown in Appendix C.

8.0 Allocation of Taxes and Fees

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 PacifiCorp's tax software system. The Washington public utility tax is allocated using the SO factor in lieu of a Washington income tax.

Franchise taxes, revenue related taxes, local business income taxes, Commission assessments and fees, and usage-related taxes are allocated Situs or treated as pass through.

Property taxes are allocated based on gross plant using the gross plant system ("GPS") factor as identified in Appendix C. State taxes enacted as a replacement for property taxes, such as the Idaho Kilowatt Hour tax, will be considered the same as property tax and allocated on the GPS factor. Amounts collected as a separate line on customer bills will be reflected as a reduction to that state's allocation of property taxes in the revenue requirement calculation.

Generation and fuel-related taxes or royalties, other than those associated with a carbon or greenhouse gas pricing program (see Section 3.7), will follow the allocation of the Resource under Section 3.2. Other taxes such as payroll taxes are embedded in the cost of expense or capital. Balances associated with the Trojan Plant decommissioning will be allocated using the Trojan Plant decommissioning factor as identified in Appendix C.

9.0 Allocation of 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 Situs assigned to the appropriate state. Those costs that cannot be directly allocated will be allocated among states consistent with the factors set forth in Appendix B.

10.0 Treatment of Oregon Direct Access Programs

Customer loads electing to be served on one- and three-year Oregon Direct Access programs will be included in the dynamic allocation factors, and the transition cost payments from these customers will be Situs assigned and allocated to Oregon.

Customers electing to be served under the Oregon five year opt-out program will be treated consistent with Order No. 15-060, as clarified through Order No. 15-067, of the Public Utility Commission of Oregon in docket UE 267, and Oregon Schedule 296, which allow Oregon Direct Access customers to permanently opt-out of cost-of-service rates after payment of ten years of transition costs. If an Oregon Direct Access customer is paying transition costs, the Oregon Direct Access customer's load(s) will be included in dynamic allocation factors, and the transition cost payments from these customers will be Situs-assigned to Oregon. If any Oregon Direct Access customer reaches the end of the 10-year period covered by the transition cost payments, the load(s) for that Oregon Direct Access customer will be excluded from dynamic allocation factors. If any Oregon Direct Access customer returns to PacifiCorp service after the end of the 10-year period covered by the transition cost payments, the load(s) for that Oregon Direct Access customer will be addressed as an increase in load under Section 11.0.

11.0 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 the Five State load, realignment of service territories, changes in economic conditions, or gain or loss of customers (unless described in Sections 10.0 or 13.0) will be reflected in changes in the dynamic allocation factors. The allocation or assignment of costs and benefits arising from a merger, sale, or acquisition transaction proposed by PacifiCorp involving more than five percent of the Five State load will be considered on a case-by-case basis in the course of Commission approval proceedings.

12.0 Excess Liability Insurance and Liability Allocation

The costs for non-wildfire related insurance premiums for excess liability and costs for non-wildfire liability not covered by insurance will be allocated using the SO factor. The costs for wildfire related insurance coverage and liability in retail service states will be addressed on a state-by-state basis.

13.0 Allocation of Costs for New Large Load

The costs associated with New Large Load that require PacifiCorp to make investments or incur costs for assets placed in service after January 1, 2026, will be assigned to the state in which the load is located. PacifiCorp will work within the regulatory framework (i.e., a special contract or tariff) within that state to assign the costs to the New Large Load customer, as determined by that state's Commission. These costs include, but are not limited to, any new distribution costs, transmission costs, generation costs (including power purchase agreements, as applicable), and contractual costs for providing electrical service (i.e., firm third-party transmission rights).

14.0 Allocation of Gain or Loss from Sale of Assets

Any gain or loss from the sale of PacifiCorp-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 not been reassigned.

15.0 Interpretation and Governance

To the extent that an issue of interpretation causes an allocation difference between multiple jurisdictions as a result of the 2026 Protocol, PacifiCorp may petition other Commissions to amend this 2026 Protocol to resolve any allocation discrepancies.

The 2026 Protocol has been developed as an integrated, interdependent whole. If any Commission disapproves, alters, or conditions approval of the 2026 Protocol, PacifiCorp may petition for an amendment to revise the 2026 Protocol.

APPENDIX A – DEFINED TERMS

For purposes of the 2026 PacifiCorp Interjurisdictional Allocation Protocol, the following terms will have the following meanings:

- **"2020 Protocol"** refers to the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol.
- **"Closure"** means the permanent retirement and termination of operation of a Resource.
- **"Commission(s)"** means a public utility commission established by statute in California, Idaho, Oregon, Utah, or Wyoming.
- **"Decommissioning Costs"** means all costs of a plant or unit removal, and environmental remediation or reclamation (including any asset retirement obligations), net of any salvage value realized, to physically retire a generation resource.
- **"Demand-Side Management 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.
- **"FERC"** means the Federal Energy Regulatory Commission.
- **"FERC Account"** refers to the specific accounting identified in Title 18 CFR §101.
- **"Five State(s)"** means the states of California, Idaho, Oregon, Utah and Wyoming.
- **"Legacy Interruptible Contract"** means the two interruptible industrial load contracts between PacifiCorp and P4 Production that began on January 1, 2022, and with Nucor-Steel Utah that began on March 1, 2022.
- **"Net Power Costs" or "NPC"** means the cost of power supply incurred, net of any sales for resale (wholesale power sales). The cost of power supply includes fuel, purchased power, and transmission of electricity by others (wheeling expense).

- **"New Large Load"** means an existing or new customer requesting new or additional service with a demand of 50 megawatts or greater.
- **"Oregon Direct Access"** means a program under Oregon's electric restructuring law (ORS 757.600 to ORS 757.687) allowing nonresidential consumers to purchase electricity from a certified electricity service supplier other than PacifiCorp.
- **"Portfolio Standards"** means any requirement to serve load or portion of load with specific types of resources, which can be measured on an energy or capacity basis.
- **"Qualifying Facility" or "QF"** means small power production or cogeneration facilities developed under the Public Utility Regulatory Policies Act of 1978 (PURPA).
- **"Resources"** means Company-owned, leased, or contracted generating plants, energy-storage facilities and mines, long term wholesale contracts, short-term purchases and sales and non-firm purchases and sales, and QF PPAs.
- "**Situs"** means the allocation of all of the cost or attribute to a single state.
- **"Trojan Plant"** means the decommissioned nuclear plant for which PacifiCorp is still recovering costs.
- **"2026 Washington Protocol"** refers to the PacifiCorp Inter-Jurisdictional Allocation Protocol for use in Washington filed in docket UE-250224 before the Washington Utilities and Transportation Commission.

2026 Protocol - Appendix B
Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
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	SE5A
		Firm	SG	SG5A
449	Provision for Rate Refund			
		Direct assigned - Jurisdiction	S	S
		Transmission	SG	SG
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			
		Water Sales	SG	SG5A
		Water Sales	SG	SG5B
454	Rent of Electric Property			
		Retail Revenues Direct assigned - Jurisdiction	S	S
		Common	SG	SG
		Other - Common	SO	SO
456	Other Electric Revenue			
		Retail Revenues Direct assigned - Jurisdiction	S	S
		Wheeling Non-firm, Other	SE	SE
		Common	SO	SO
		Wheeling - Firm, Other	SG	SG
		Customer Related	CN	CN

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
Miscellaneous Revenues				
41160	Gain on Sale of Utility Plant - CR			
		Distribution	S	S
		Production - Jim Bridger Units 1 & 2, Non-Emitting (except Rolling Hills)	SG	SG5A
		Production - Thermal (except Chehalis and Jim Bridger Units 1 & 2)	SG	SG5B
		Production - Rolling Hills	SG	SG5C
		Production - Chehalis	SG	S
		Transmission	SG	SG
		General Office	SO	SO
41170	Loss on Sale of Utility Plant			
		Distribution	S	S
		Production - Jim Bridger Units 1 & 2, Non-Emitting (except Rolling Hills)	SG	SG5A
		Production - Thermal (except Chehalis and Jim Bridger Units 1 & 2)	SG	SG5B
		Production - Rolling Hills	SG	SG5C
		Production - Chehalis	SG	S
		Transmission	SG	SG
		General Office	SO	SO
4118	Gain from Emission Allowances			
		SO2 Emission Allowance sales	SE	SE5B
41181	Gain from Disposition of NOX Credits			
		NOX Emission Allowance sales	SE	SE5B
421	(Gain) / Loss on Sale of Utility Plant			
		Distribution	S	S
		Production - Jim Bridger Units 1 & 2, Non-Emitting (except Rolling Hills)	SG	SG5A
		Production - Thermal (except Chehalis and Jim Bridger Units 1 & 2)	SG	SG5B
		Production - Rolling Hills	SG	SG5C
		Production - Chehalis	SG	S
		Transmission	SG	SG
		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			
		Jim Bridger Units 1 & 2	SG	SG5A
		Steam Plant, Other Than Jim Bridger Units 1 & 2	SG	SG5B
501	Fuel Related			
		Jim Bridger Units 1 & 2	SE	SE5A
		Other	SE	SE5B
503	Steam From Other Sources			
		Steam Royalties	SE	SE5A
		Steam Royalties	SE	SE5B
509	Allowances			
		California Wholesale GHG Obligation	SG	SG5A
		California Retail GHG Obligation	S	S

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
Nuclear Power Generation				
517 - 532	Nuclear Power O&M			
		Nuclear Plants O&M	SG	SG5A
Hydraulic Power Generation				
535 - 545	Hydro O&M			
		Hydro Plant O&M	SG	SG5A
Solar Power Generation				
558	Solar Plant O&M			
		Solar Plant O&M	S	S
		Solar Plant O&M	SG	SG5A
Wind Power Generation				
558	Wind Plant O&M			
		Wind Plant O&M- Except Rolling Hills	SG	SG5A
		Wind Plant O&M - Rolling Hills Wind	SG	SG5C
Renewable Generation				
559	Renewable Plant O&M			
		Geothermal	SG	SG5A
Other Power Generation				
546, 548-554	Operation Super & Engineering			
		Other Production Plant O&M - Chehalis	SG	S
		Other Production Plant, Except Chehalis	SG	SG5B
547	Fuel			
		Other Fuel Expense (except Chehalis)	SE	SE5B
		Chehalis	SE	S
Other Power Supply				
555	Purchased Power			
		Tracking Mechanisms	S	S
		New QFs - Post 2020		S
		QFs - Pre 2020		SG5B
		Firm	SG	SG5A
		Non-firm	SE	SE5A
		EDAM / EIM		SG5A
556	System Control & Load Dispatch			
		Other Expenses	SG	SG
557	Other Expenses			
		Direct assigned - Jurisdiction	S	S
		Other Expenses	SE	SE5A
		Other Expenses	SE	SE5B
		Other Expenses	SG	SG
Transmission Expense				
560-564, 566-573	Transmission O&M			
		Transmission Plant O&M	SG	SG
565	Transmission of Electricity by Others			
		Firm Wheeling	SG	SG5A
		Non-Firm Wheeling	SE	SE5A
		GRID Management Charge	SG	SG5A
Energy Storage Expense				
578	Energy Storage O&M			
		Energy Storage O&M	N/A	S
		Energy Storage O&M	N/A	SG5A

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
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	SE5B
		FERC Regulatory Expense - Transmission	SG	SG
		FERC Regulatory Expense - Hydro	SG	SG5A
		General	SO	SO
Depreciation Expense				
403SP	Steam Depreciation			
		Jim Bridger Units 1 & 2	SG	SG5A
		Steam Plant -Except Jim Bridger Units 1 & 2	SG	SG5B
403NP	Nuclear Depreciation			
		Nuclear Plant	SG	SG5A
403HP	Hydro Depreciation			
		Hydro	SG	SG5A
403OP	Other Production Depreciation			
		Other Production Plant - Chehalis	SG	S
		Other Production Plant, Except Chehalis	SG	SG5B
403XP	Solar Production Depreciation			
		Solar Plant	S	S
		Solar Plant	SG	SG5A
403WP	Wind Production Depreciation			
		Wind - Except Rolling Hills	SG	SG5A
		Rolling Hills Wind	SG	SG5C
403RP	Renewable Production Depreciation			
		Geothermal	SG	SG5A

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
403EP	Energy Storage Depreciation			
		Energy Storage	N/A	S
		Energy Storage	N/A	SG5A
403TP	Transmission Depreciation			
		Transmission Plant	SG	SG
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			
		Mining	SE	SE5B
		Customer Related	CN	CN
		General	SO	SO
403MP	Mining Depreciation			
		Mining Plant	SE	SE5B
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	SG5B
404IP	Amort of LT Plant - Intangible Plant			
		General	SO	SO
		Mining Plant	SE	SE5B
		Customer Related	CN	CN
404MP	Amort of LT Plant - Mining Plant			
		Mining Plant	SE	SE5B
404HP	Amortization of Other Electric Plant			
		Hydro	SG	SG5A
405	Amortization of Other Electric Plant			
		Direct assigned - Jurisdiction	S	S

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
406	Amortization of Plant Acquisition Adj			
		Direct assigned - Jurisdiction	S	S
		Thermal Production Plant	SG	SG5B
		Non-Emitting Production Plant		SG5A
		Transmission		SG
407	Amort of Prop Losses, Unrec Plant, etc.			
		Direct assigned - Jurisdiction	S	S
		Thermal Production Plant	SG	SG5B
		Non-Emitting Production Plant	SG	SG5A
		Transmission	SG	SG
Taxes Other Than Income				
408	Taxes Other Than Income			
		Direct assigned - Jurisdiction	S	S
		Property	GPS	GPS
		System Taxes	SO	SO
		Misc Energy	SE	SE
		Misc Production	SG	SG5A
		Misc Production - Rolling Hills	SG	SG5C
Deferred ITC				
41140	Deferred Investment Tax Credit - Fed			
		ITC	DGU	DGU
41141	Deferred Investment Tax Credit - Idaho			
		ITC	DGU	DGU
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

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
Deferred Income Taxes				
41010	Deferred Income Tax - DR			
		Direct assigned - Jurisdiction	S	S
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Transmission	SG	SG
		Customer Related	CN	CN
		General	SO	SO
		Property Tax related	GPS	GPS
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJD
		Distribution	SNPD	SNPD
		Mining Plant	SE	SE5B
		Bad Debt	BADDEBT	BADDEBT
		Tax Depreciation	TAXDEPR	TAXDEPR
41110	Deferred Income Tax -CR			
		Direct assigned - Jurisdiction	S	S
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Transmission	SG	SG
		Customer Related	CN	CN
		General	SO	SO
		Property Tax related	GPS	GPS
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJD
		Distribution	SNPD	SNPD
		Mining Plant	SE	SE5B
		Contributions in Aid of Construction	CIAC	CIAC
		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	SE5B
		General	SO	SO
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Transmission	SG	SG
		Depreciation	SCHMDEXP	SCHMDEXP

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
SCHMAT	Additions - Temporary			
		Direct assigned - Jurisdiction	S	S
		Bad Debt	BADDEBT	BADDEBT
		Contributions in Aid of Construction	CIAC	CIAC
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJD
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Mining Plant	SE	SE5B
		Transmission	SG	SG
		Property Tax	GPS	GPS
		General	SO	SO
		Depreciation	SCHMDEXP	SCHMDEXP
		Distribution	SNPD	SNPD
Schedule - M Deductions				
SCHMDF	Deductions - Flow Through			
		Direct Assigned - Jurisdiction	S	S
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Transmission	SG	SG
SCHMDP	Deductions - Permanent			
		Direct Assigned - Jurisdiction	S	S
		Mining Related	SE	SE5B
		Depreciation	SCHMDEXP	SCHMDEXP
		Miscellaneous	SNP	SNP
		General	SO	SO
SCHMDT	Deductions - Temporary			
		Direct Assigned - Jurisdiction	S	S
		Bad Debt	BADDEBT	BADDEBT
		Miscellaneous	SNP	SNP
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Mining related	SE	SE5B
		Transmission	SG	SG
		Property Tax	GPS	GPS
		General	SO	SO
		Depreciation	TAXDEPR	TAXDEPR
		Distribution	SNPD	SNPD
		Customer Related	CN	CN

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
State Income Taxes				
40911	State Income Taxes			
40911		Income Before Taxes	CALCULATED	CALCULATED
40911		Renewable Energy Tax Credit, Except Rolling Hills	SG	SG5A
40911		Renewable Energy Tax Credit - Rolling Hills		SG5C
40911		PacifiCorp Minerals Inc.	SE	SE5B
40911		Foreign Tax Credit	SO	SO
Adjustments to Calculated Tax				
	Federal Income Taxes			
40910		FIT True-up	S	S
40910		Renewable Energy / Production Tax Credit, Except Rolling Hills	SG	SG5A
40910		Renewable Energy / Production Tax Credit - Rolling Hills		SG5C
40910		Fuel Tax Credit		SE5A
40910		Fuel Tax Credit		SE5B
40910		Misc.		SO
Steam Production Plant				
310 - 316	Steam Plants			
		Jim Bridger Units 1 & 2	SG	SG5A
		Steam Plant other than Jim Bridger Units 1 & 2	SG	SG5B
Nuclear Production Plant				
320-325	Nuclear Plant			
		Nuclear Plant	SG	SG5A
Hydraulic Plant				
330-336	Hydro Plant			
		Hydro	SG	SG5A
Solar Production Plant				
338	Solar Plant			
		Solar Plant	S	S
		Solar Plant	SG	SG5A
Wind Production Plant				
338	Wind Plant			
		Wind - Except Rolling Hills	SG	SG5A
		Rolling Hills Wind	SG	SG5C
Renewable Production Plant				
339	Renewable Plant			
		Geothermal	SG	SG5A
Other Production Plant				
340-346	Other Production Plant			
		Other Production Plant - Chehalis	SG	S
		Other Production Plant, Except Chehalis	SG	SG5B
Transmission Plant				
350-359	Transmission Plant			
		Transmission Plant	SG	SG

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
Distribution Plant				
360-373	Distribution Plant			
		Direct assigned - Jurisdiction	S	S
		Other Distribution	SNPD	SNPD
Energy Storage				
387	Energy Storage Plant			
		Energy Storage Plant	N/A	S
		Energy Storage Plant	N/A	SG5A
General Plant				
389 - 398	General Plant			
		Direct assigned - Jurisdiction	S	S
		Customer Related	CN	CN
		General	SO	SO
		Mining	SE	SE5B
399	Coal Mine			
		Mining Plant	SE	SE5B
1011346	General Gas Line Capital Leases			
		Capital Lease		S
		Capital Lease	SG	SG5B
1011390	General Capital Leases			
		Direct assigned - Jurisdiction	S	S
		General	SO	SO
		Chehalis	SG	S
		Other Thermal Production	SG	SG5B
		Transmission	SG	SG
Intangible Plant				
301	Organization			
		Direct assigned - Jurisdiction	S	S
302	Franchise & Consent			
		Direct assigned - Jurisdiction	S	S
		Other Thermal Production	SG	SG5B
		Production - Non-Emitting	SG	SG5A
		Transmission	SG	SG
303	Miscellaneous Intangible Plant			
		Customer Related	CN	CN
		General	SO	SO
		Mining	SE	SE5B
303	Less Non-Utility Plant			
		Direct assigned - Jurisdiction	S	S

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
Rate Base Additions				
105	Plant Held For Future Use			
		Direct assigned - Jurisdiction	S	S
		Other Thermal Production	SG	SG5B
		Production - Non-Emitting	SG	SG5A
		Transmission	SG	SG
		Mining Plant	SE	SE5B
114	Electric Plant Acquisition Adjustments			
		Direct assigned - Jurisdiction	S	S
		Other Thermal Production	SG	SG5B
		Production - Non-Emitting		SG5A
		Transmission	SG	SG
115	Accum Provision for Asset Acquisition Adjustments			
		Direct assigned - Jurisdiction	S	S
		Other Thermal Production	SG	SG5B
		Production - Non-Emitting		SG5A
		Transmission	SG	SG
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	SE5B
152	Fuel Stock - Undistributed			
		Steam Production Plant	SE	SE5B
25316	UAMPS Working Capital Deposit			
		Mining Plant	SE	SE5B
25317	DG&T Working Capital Deposit			
		Mining Plant	SE	SE5B
25319	Provo Working Capital Deposit			
		Mining Plant	SE	SE5B

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
154	Materials and Supplies			
		Direct assigned - Jurisdiction	S	S
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Transmission	SG	SG
		Mining	SE	SE5B
		General	SO	SO
		Distribution	SNPD	SNPD
163	Stores Expense Undistributed			
		General	SO	SO
165	Prepayments			
		Direct assigned - Jurisdiction	S	S
		Property Tax	GPS	GPS
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Transmission	SG	SG
		Mining	SE	SE5B
		General	SO	SO
182M	Misc Regulatory Assets			
		Direct assigned - Jurisdiction	S	S
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Transmission	SG	SG
		Mining	SE	SE5B
		General	SO	SO
186M	Misc Deferred Debits			
		Direct assigned - Jurisdiction	S	S
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Transmission	SG	SG
		General	SO	SO
		Mining	SE	SE5B

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
Working Capital				
CWC	Cash Working Capital			
		Direct assigned - Jurisdiction	S	S
OWC	Other Working Capital			
131		Cash	SNP	SNP
141		Notes Receivable	SO	SO
143		Other Accounts Receivable	SO	SO
232		Accounts Payable	SO	SO
232		Accounts Payable	SE	SE5B
232		Accounts Payable	SG	SG
25330		Other Deferred Credits - Misc	SE	SE5B
230		Other Deferred Credits - Misc	SE	SE5B
254105		ARO Reg Liability	SE	SE5B
Rate Base Deductions				
235	Customer Service Deposits			
		Direct assigned - Jurisdiction	S	S
2281	Prov for Property Insurance			
		Prov for Property Insurance - Jurisdiction	S	S
		Prov for Property Insurance	SO	SO
2282	Prov for Injuries & Damages			
		Prov for Injuries & Damages - Jurisdiction	S	S
		Prov for Injuries & Damages	SO	SO
2283	Prov for Pensions and Benefits			
		Prov for Pensions and Benefits	SO	SO
22841	Accum Misc Oper Prov-Other			
		Chehalis WA EFSEC C02 Mitigation Oblig		S
254105	FAS 143 ARO Regulatory Liability			
		ARO	S	S
		Trojan Plant	TROJD	TROJD
230	Asset Retirement Obligation			
		Trojan Plant	TROJD	TROJD
252	Customer Advances for Construction			
		Direct assigned - Jurisdiction	S	S
		Transmission	SG	SG
		Customer Related	CN	CN
25398	S02 Emissions			
		S02 Emissions	SE	SE5B
25399	Other Deferred Credits			
		Direct assigned - Jurisdiction	S	S
		Transmission	SG	SG
		General	SO	SO
		Mining	SE	SE5B

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
254	Regulatory Liabilities			
		Insurance Provision	SO	SO
190	Accumulated Deferred Income Taxes			
		Direct assigned - Jurisdiction	S	S
		Bad Debt	BADDEBT	BADDEBT
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Transmission	SG	SG
		Customer Related	CN	CN
		General	SO	SO
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJD
		Distribution	SNPD	SNPD
		Mining Plant	SE	SE5B
281	Accumulated Deferred Income Taxes			
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Transmission	SG	SG
282	Accumulated Deferred Income Taxes			
		Direct assigned - Jurisdiction	S	S
		Depreciation	DITBAL	DITBAL
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Transmission	SG	SG
		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	SE5B

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
283	Accumulated Deferred Income Taxes			
		Direct assigned - Jurisdiction	S	S
		Depreciation	DITBAL	DITBAL
		Chehalis		S
		Non-Emitting and Jim Bridger Units 1 & 2	SG	SG5A
		Other Thermal Production	SG	SG5B
		Rolling Hills		SG5C
		Transmission	SG	SG
		Customer Related	CN	CN
		General	SO	SO
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJD
		Property Tax	GPS	GPS
		Mining Plant	SE	SE5B
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	SG
Production Plant Accum Depreciation				
108SP	Steam Prod Plant Accumulated Depr			
		Jim Bridger Units 1 & 2	SG	SG5A
		Steam Plant other than Jim Bridger Units 1 & 2	SG	SG5B
108NP	Nuclear Prod Plant Accumulated Depr			
		Nuclear Plant	SG	SG5A
108HP	Hydraulic Prod Plant Accum Depr			
		Hydro	SG	SG5A
108XP	Solar Plant - Accumulated Depr			
		Solar Plant	S	S
		Solar Plant	SG	SG5A
108WP	Wind Plant - Accumulated Depr			
		Wind - Except Rolling Hills	SG	SG5A
		Rolling Hills Wind	SG	SG5C
108RP	Renewable Plant - Accumulated Depr			
		Blundell	SG	SG5A
108OP	Other Production Plant - Accum Depr			
		Other Production Plant - Chehalis	SG	S
		Other Production Plant	SG	SG5B
108EP	Energy Storage Plant Accum Depr			
		Energy Storage	N/A	S
		Energy Storage	N/A	SG5A
Trans Plant Accum Depr				
108TP	Transmission Plant Accumulated Depr			
		Transmission Plant	SG	SG

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
			2020 PROTOCOL	2026 Protocol
FERC ACCT	ACCT NAME	REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR	FACTOR	FACTOR
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.			
		Direct assigned - Jurisdiction	S	S
		Customer Related	CN	CN
		General SO	SO	SO
		Mining Plant	SE	SE5B
108MP	Mining Plant Accumulated Depr.			
		Mining Plant	SE	SE5B
1081390	Accum Depr - Capital Lease			
		General	SO	SO
1081399	Accum Depr - Capital Lease			
		Direct assigned - Jurisdiction	S	S
Accum Provision For Amortization				
111SP	Accum Prov for Amort-Steam			
		Steam Plants	SG	SG5A
		Steam Plants	SG	SG5B
111GP	Accum Prov for Amort-General			
		Direct assigned - Jurisdiction	S	S
		Customer Related	CN	CN
		General SO	SO	SO
111HP	Accum Prov for Amort-Hydro			
		Hydro	SG	SG5A
111IP	Accum Prov for Amort-Intangible Plant			
		General	SO	SO
		Mining	SE	SE5B
		Customer Related	CN	CN
111IP	Less Non-Utility Plant			
		Direct assigned - Jurisdiction	S	S
111390	Accum Prov Amort - Capital Leases			
		Distribution	S	S
		Other Thermal Production	SG	SG5B
		Production - Non-Emitting	SG	SG5A
		General	SO	SO

APPENDIX C - DEFINITIONS OF ALLOCATION FACTORS

i denotes count of jurisdictions. j denotes count of month in a year. N is the number of regulatory jurisdictionsin which PacifiCorp operates and to which it allocates costs.

Bad Debt Expense Factor ("BADDEBT")

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

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.

Contributions in Aid of Construction Factor ("CIAC")

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

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.

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.

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.

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.

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 DGU factor is used to allocate some Deferred Investment Tax Credits.

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.

Portfolio Allocation Factor One ("PA1")

$$PA1 = 100\% - SGF^*{}_i$$

where:

$SG\text{-}F^*{}_i$	=	$SG\text{-}F_i$ if i is Washington, otherwise 0.
$SG\text{-}F_i$	=	System Generation – Fixed Factor for jurisdiction i.

The PA1 factor in which Washington receives a fixed allocation. This factor is used to calculate the SG5A and SE5A allocation factors. The $SG\text{-}F_i$ factor is defined below.

Portfolio Allocation Factor Two ("PA2")

$$PA2 = 100\%$$

The PA2 factor in which Washington does not receive an allocation. This factor is used to calculate the SG5B and SE5B allocation factors.

Portfolio Allocation Factor Three ("PA3")

$$PA3 = 100\% - SGFR^*{}_i$$

where:

$SG\text{-}FR^*{}_i$	=	$SG\text{-}FR_i$ if i is Washington, otherwise 0.
$SG\text{-}FR_i$	=	System Generation – Fixed Factor for jurisdiction i.

The PA3 factor in which Washington receives a fixed allocation. This factor is used to calculate the SG5C allocation factor for Rolling Hills Wind. The $SG\text{-}FR_i$ factor is defined below.

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.

<u>Situs – Situs Factor("S")</u>

$$S_i = 100\%$$

where:

S_i	=	**Situs Factor** for jurisdiction i.

<u>System Capacity Factor ("SC")</u>

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

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. The peak load is further adjusted to exclude the peak load of Load Control Demand-Side Management programs as defined in the 2026 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. The SC factor is used to calculate the System Generation factor and the SO factor.

<u>System Energy Factor ("SE")</u>

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

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 non-firm wheeling revenue, calculate the SO factor and to calculate the SE5 factor. It 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.

<u>System Energy (five state) Factor ("SE5")</u>

$$SE5_i = \frac{SE^*{}_i}{\sum_{i=1}^{N} SE^*{}_i}$$

where:

$SE5_i$	=	**System Energy (five state) Factor** for jurisdiction i.
SE^*_i	=	SE_i if i is a CA, OR, WY, UT, ID jurisdiction, otherwise 0.
SE_i	=	System Energy Factor for jurisdiction i.
N	=	Number of jurisdictions.

The SE5 factor is dynamically calculated for customers in California, Idaho, Oregon, Utah and Wyoming. It is calculated as the ratio of the individual five state jurisdiction's SE factor divided by the sum of the five states SE factors. The SE5 factor is used for the calculation of the SE5A and SE5B allocation factors.

<u>System Energy (five state) A Factor ("SE5A")</u>

$$SE5A_i = SE5_i * PA1$$

where:

$SE5A_i$	=	**System Energy (five state) A Factor** for jurisdiction i.
$SE5_i$	=	System Energy (five state) Factor for jurisdiction i.
$PA1$	=	Portfolio Allocation One Factor (PA1).

This factor allocates energy-related costs for Jim Bridger Units 1 and 2 and non-firm wholesale sales and purchased power. The SE5A factor is calculated by multiplying the SE5 factor by the PA1 factor.

<u>System Energy (five state) B Factor ("SE5B")</u>

$$SE5B_i = SE5_i * PA2$$

where:

$SE5B_i$	=	**System Energy (five state) B Factor** for jurisdiction i.
$SE5_i$	=	System Energy (five state) Factor for jurisdiction i.
$PA2$	=	Portfolio Allocation Two Factor (PA2).

This factor allocates energy-related costs for other thermal units excluding Chehalis and Jim Bridger 1&2.
The SE5B factor is calculated by multiplying the SE5 factor by the PA2 factor.

<u>System Generation Factor ("SG")</u>

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

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 transmission related costs. It is also used to calculate the SG5 factor. It is calculated using a weighting of 75% of the SC factor and 25% of the SE factor for a jurisdiction.

System Generation (five state) Factor ("SG5")

$$SG5_i = \frac{SG^*{}_i}{\sum_{i=1}^{N} SG^*{}_i}$$

where:

$SG5_i$	=	**System Generation (five state) Factor** for jurisdiction i.
$SG^*{}_i$	=	SG_i if i is a CA, OR, WY, UT, ID jurisdiction, otherwise 0.
SG_i	=	System Generation Factor for jurisdiction i.
N	=	Number of jurisdictions.

The SG5 factor is dynamically calculated for customers in California, Idaho, Oregon, Utah and Wyoming. It is calculated as the ratio of the individual five state jurisdiction's SG factor divided by the sum of the five states SG factors. The SG5 factor is used for the calculation of the SG5A, SG5B and SG5C allocation factors.

System Generation (four state) Factor ("SG4")

$$SG4_i = \frac{SG^*{}_i}{\sum_{i=1}^{N} SG^*{}_i}$$

where:

$SG4_i$	=	**System Generation (four state) Factor** for jurisdiction i.
$SG^*{}_i$	=	SG_i if i is a CA, WY, UT, ID jurisdiction, otherwise 0.
SG_i	=	System Generation Factor for jurisdiction i.
N	=	Number of jurisdictions.

The SG4 factor is dynamically calculated for customers in California, Idaho, Utah and Wyoming. It is calculated as the ratio of the individual four state jurisdiction's SG factor divided by the sum of the four states SG factors. The SG4 factor is used for the calculation of the SG5C allocation factor.

System Generation (five state) A Factor ("SG5A")

$$SG5A_i = SG5_i * PA1$$

where:

$SG5A_i$	=	**System Generation (five state) A Factor** for jurisdiction i.
$SG5_i$	=	System Generation (five state) Factor for jurisdiction i.
$PA1$	=	Portfolio Allocation One Factor (PA1).

This factor allocates costs for non-emitting resources and Jim Bridger Units 1 and 2, excluding Rolling Hills Wind and QFs. The SG5A factor is calculated by multiplying the SG5 factor by the PA1 factor.

System Generation (five state) B Factor ("SG5B")

$$SG5B_i = SG5_i * PA2$$

where:

$SG5B_i$	=	**System Generation (five state) B Factor** for jurisdiction i.
$SG5_i$	=	System Generation (five state) Factor for jurisdiction i.
$PA2$	=	Portfolio Allocation Two Factor (PA2).

This factor allocates costs for other thermal units excluding Chehalis and Jim Bridger 1&2. The SG5B factor is calculated by multiplying the SG5 factor by the PA2 factor.

System Generation (five state) C Factor ("SG5C")

$$SG5C_i = SG4_i * PA3$$

where:

$SG5C_i$	=	**System Generation (five state) C Factor** for jurisdiction i.
$SG4_i$	=	System Generation (four state) Factor for jurisdiction i.
$PA3$	=	Portfolio Allocation Three Factor (PA3).

This factor allocates costs for Rolling Hills Wind. The SG5C factor is calculated by multiplying the SG4 factor by the PA3 factor.

System Generation Factor – Fixed ("SG-F")

$$SG\_F_i = SG\_F^*{}_i$$

where:

$SG\text{-}F_i$	=	**System Generation – Fixed Factor** Rolling Hills for jurisdiction i.
$SG\text{-}F^*{}_i$	=	7.8971% if i is the WA jurisdiction, otherwise 0.

The SG_F factor is the Washington fixed factor used to allocate costs for non-emitting resources and Jim Bridger Units 1 and 2, excluding Rolling Hills Wind and QFs. The factor is also used in calculating the SG5A factor.

System Generation Factor – Fixed Rolling Hills ("SG-FR")

$$SGFR_i = SGFR^*{}_i$$

where:

SG-FR$_i$	=	**System Generation – Fixed Rolling Hills Factor** for jurisdiction i.
SG-FR$^*_i$	=	34.8727% if i is the WA jurisdiction, otherwise 0.

The SG_FR factor is the Washington fixed factor used to allocate Rolling Hills Wind. The factor is also used in calculating the SG5C factor.

System Gross Plant Distribution Factor ("SGPD")

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

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. This factor is used to calculate the SO factor.

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.

System Net Plant Factor ("SNP")

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

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.

System Overhead Factor ("SO")

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

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 is calculated by taking the sum of the SC, SE and SGPD factor for a jurisdiction and dividing by three.

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 PacifiCorp tax depreciation.)
N	=	Number of jurisdictions.

The TAXDEPR factor allocates depreciation-related tax costs.

<u>Trojan Decommissioning Factor ("TROJD")</u>

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

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.

APPENDIX D – LEGACY INTERRUPTIBLE CONTRACTS

The following Legacy Interruptible Contracts covered under Section 3.3 are:

- Nucor-Steel Utah beginning on March 1, 2022
- P4 Production beginning on January 1, 2022

Legacy Interruptible Contracts with Customer Ancillary Service Attributes

For allocation purposes, Legacy Interruptible 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 ancillary service contract's rate.

Loads of Legacy Interruptible Contract customers will be included in all load-based dynamic allocation factors.

When interruptions of a Legacy Interruptible 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 Legacy Interruptible Contract customer, before any discounts for ancillary services attributes of the Legacy Interruptible Contract, will be assigned to the state where the Legacy Interruptible Contract customer is located.

Discounts from tariff prices provided in a Legacy Interruptible Contract that recognize ancillary services attributes of the contract, and payments to retail customers for ancillary services will be allocated among states using the SG5A factor.

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 Legacy Interruptible Contract customer load associated with the buy-through will not be included in the calculation of dynamic allocation factors, and the revenue associated with the buy-through will not be included in state revenues.

Rocky Mountain Power
Exhibit RMP___(RTL-2)
Docket No. 25-035-47
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick T. Link

Washington 2026 Protocol

August 2025

The Washington 2026 Protocol

Introduction

PacifiCorp d/b/a Pacific Power and Light Company (PacifiCorp or Company) proposes this cost allocation protocol to address the imminent removal of coal resources from Washington rates, as required by Washington's Clean Energy Transformation Act (CETA), and the reallocation of existing resources using fixed allocation factors.

Background

PacifiCorp is a multi-jurisdictional electric utility that provides services in six states (California, Idaho, Oregon, Utah, Wyoming, and Washington). Currently, Washington uses the Washington Inter-Jurisdictional Allocation Methodology (WIJAM) for determining which costs are eligible for recovery in rates from customers in PacifiCorp's Washington service area.[1]

In the context of inter-jurisdictional cost allocation, the Washington Utilities and Transportation Commission (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 a cost allocation 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 and persuasive showing demonstrating that the proposed change is appropriate."[6]

Terms of the Protocol

1. **Implementation.** The Washington 2026 Protocol includes modifications to the WIJAM subject to approval by the Commission, including the implementation of fixed factors, removal of coal resources, and the situs allocation of the Chehalis generating facility among other changes. The Washington 2026 Protocol will be implemented in two phases. The Washington 2026 Protocol is part of the larger integrated transition to the 2026 Protocol for all the states in which PacifiCorp serves customers and represents the first step of Phase 1. Phase 2 will involve the introduction of fixed allocation factors in other states, a possible reconciliation of new issues that may arise as other states review implementation of the 2026 Protocol in their jurisdictions, the use of market settlements and locational marginal pricing to track net power costs, and potential review of transmission allocations.

[1] Prior to the WIJAM methodology being approved in Docket No. UE-191024, PacifiCorp had used the Western Control Area methodology, which was approved in Docket No. UE-061546.
[2] *See* RCW 80.04.250.
[3] Docket No. UE-050684, Order 04 ¶ 68.
[4] Docket No. UE-130043, Order 05 ¶ 92–94.
[5] *Id.*
[6] *Id.*

2. **Prudence.** The proposed allocation of a particular expense or investment under the Washington 2026 Protocol 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 the Washington 2026 Protocol 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. **System Transmission.** All existing system transmission costs and benefits will continue to be allocated using the System Generation (SG) factor as specified in Attachment 1.

4. **Existing Resources**. Existing resources will be allocated using the Fixed SG-Factor (SG-F) as identified below.

   4.1. **Existing Non-Emitting Resources**.[7] The allocation factors for non-emitting resources that are not qualifying facilities as defined under the Public Utility Regulatory Policies Act are as follows:

	Allocation Factor
Rolling Hills Wind (SG-FR)	34.873%
Existing Non-emitting Resources (SG-F)	7.897%

   4.2. **Existing Natural Gas Resources.** The Hermiston natural gas plant will be removed from Washington rates. Washington will be allocated the following natural gas resources using the fixed factors identified below:

	Allocation Factor
Chehalis	100%
Jim Bridger 1 (SG-F)	7.897%
Jim Bridger 2 (SG-F)	7.897%

5. **Existing and Future Qualifying Facilities.** The costs and benefits of existing Washington power purchase agreements for Qualifying Facilities, as defined under the Public Utility Regulatory Policies Act, will continue to be situs assigned to Washington.

6. **Existing Coal Resources.** Consistent with RCW 19.405.030, PacifiCorp will remove from Washington rates all operating costs and benefits associated with Bridger Units 3-4 and Colstrip Unit 4 on December 31, 2025.

[7] Existing Resources are non-emitting resources that have been system allocated and in-service before January 1, 2027 and included in the 2025 PCORC.

7. **New Resources.** New Resources, that are not qualifying facilities as defined under the Public Utility Regulatory Policies Act, acquired for Washington after April 1, 2025, will be assigned on a situs basis to Washington unless circumstances justify a cost-sharing proposal with other states. If circumstances allow, then PacifiCorp may propose an alternative allocation at or before a prudence review occurs for a new resource.

8. **Net Power Costs.** Forecasted net power costs for ratemaking purposes will be allocated consistent with Sections 3,4,5,6, and 7. Additionally, Washington customers will receive all direct and indirect benefits associated with their proportional system-allocated share of existing transmission, including Western Energy Imbalance Market and Extended Day-Ahead Market benefits.

    8.1. PacifiCorp's energy supply management's risk management policy will be modified to create a separate book for Washington. The risk management policy will create limits to address resource adequacy and price volatility based on the Washington load and resources. Purchases made in the Washington book in accordance with the risk management policy will be situs assigned to Washington.

    8.2. Actual Net Power Costs. Actual net power costs for ratemaking purposes will include only the generation resources and situs assigned purchases in section 7.1 that are included in Washington rates.

9. **System Overhead (2026 SO Factor).** 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 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 identified in the 2020 Protocol as the Post-Interim SO Factor.

    9.1. PacifiCorp will propose a mechanism to manage the Company's excess liability insurance costs and separately address the inter-jurisdictional allocation of these costs in that filing.

10. **Decommissioning Costs of Coal-Fired Resource Being Removed from Washington Rates.** Washington will continue to be allocated ongoing and expected decommissioning expenses for a WIJAM/WCA share of Jim Bridger Units 3-4 and Colstrip Unit 4 consistent with the previous terms of the WIJAM.

11. **Decommissioning Costs of Gas-Fired Resources for Washington.** PacifiCorp will address the decommissioning costs of gas-fired resources that have been removed from or reassigned to Washington in a future rate proceeding or through Phase 2 of the cost allocation process.

12. This Protocol proposes modifications to the WIJAM, which serves as the basis for allocating costs in Washington. PacifiCorp will allocate costs based on the WIJAM and

the preceding WCA subject to the modifications in this Washington 2026 Protocol for ratemaking purposes in Washington unless a different cost allocation method is approved by the Commission.

13. Attachment 1 contains updated allocation factors that reflect the changes necessary to implement the Washington 2026 Protocol in this 2025 Washington power cost only rate case (PCORC). Allocation factors will default to the approved WIJAM allocation factors if they are not specifically contained in Attachment 1. Attachment 1 may be updated again when PacifiCorp files its next General Rate Case to revise the factors to reflect the implementation of this Protocol as described in Section 1.

ATTACHMENT 1

Any account/factor combo that does not show up in this table is not part of the proposed changes in the Washington 2026 Protocol and default back to the WIJAM approved allocations

FERC ACCOUNT	DESCRIPTION		WIJAM	Modified Factors
447NPC	Sales for Resale-NPC		SG SE	SG-F SG-F
Steam Power Generation 500, 502, 504-514	Steam Plant O&M	Colstrip 4 JB 1&2 JB 3&4	CAGW JBG JBG	System - Non-WA SG-F System - Non-WA
501	Fuel Related	 Colstrip 4 JB 1&2 JB 3&4	SE CAGW JBE JBG	SG-F System - Non-WA SG-F System - Non-WA
501NPC	Fuel Related	Colstrip 4 JB 1&2 JB 3&4	CAEW JBE JBG	System - Non-WA SG-F System - Non-WA
503NPC	Steam From Other Sources		SE	SG-F
Hydraulic Power Generation 535 - 454	Hydro Plant O&M		SG	SG-F
Solar Power Generation 558	Solar Plant O&M		S	Situs
Wind Power Generation 558	Wind Plant O&M		SG	SG-F
Renewable Generation 559	Renewable Plant O&M	Geothermal	SG	SG-F
Other Power Generation 546, 548-554	Other Production Plant O&M	Chehalis Hermiston	CAGW CAGW	Situs - WA Situs - Non-WA
547NPC	Fuel-NPC	 Chehalis Hermiston	JBG CAGW CAGW	SG-F Situs - WA Situs - Non-WA
Other Power Supply 555NPC	Purchased Power-NPC		SG SE	SG-F SG-F
556	System Control & Load Dispatch		SG	SG-F
557	Other Expenses		SG SO	SG-F SO

FERC ACCOUNT	DESCRIPTION	WIJAM	Modified Factors
565NPC	Transmission of Electricity by Others-NPC		
		SG	SG-F
		SE	SG-F
Depreciation Expense			
403SP	Steam Depreciation		
	Colstrip 4	CAGW	System - Non-WA
	JB 1&2	JBG	SG-F
	JB 3&4	JBG	System - Non-WA
403HP	Hydro Depreciation		
		SG	SG-F
403OP	Other Production Depreciation		
	Chehalis	CAGW	Situs - WA
	Hermiston	CAGW	Situs - Non-WA
403XP	Solar Production Depeciation		
		S	Situs
403WP	Wind Production Depreciation		
	Wind - Except Rolling Hills	SG	SG-F
	Rolling Hills Wind	SG	SG-FR
403RP	Renewable Production Depreciation		
	Geothermal	SG	SG-F
Amortization Expense			
404HP	Amortization of Other Electric Plant		
		SG	SG-F
Deferred Income Taxes			
41110	Deferred Income Tax - Federal-CR		
	Production	SG	SG-F
		SO	SO
	JB 1&2	JBG	SG-F
	JB 3&4	JBG	System - Non-WA
	Colstrip 4	CAGW	System - Non-WA
	Chehalis	CAGW	Situs - WA
	Hermiston	CAGW	Situs - Non-WA
	Rolling Hills Wind	SG	SG-FR
Adjustments to Calculated Tax:			
40910		SO	SO
40910		SG	SG-F
Steam Production Plant			
310 - 316	Steam Plant		
	Colstrip 4	CAGW	System - Non-WA
	JB 1&2	JBG	SG-F
	JB 3&4	JBG	System - Non-WA
Hydraulic Plant			
330 - 336	Hydro Plant		
		SG	SG-F
Solar Production Plant			
338	Solar Plant		
		S	Situs
Wind Production Plant			
338	Wind Plant		
	Wind - Except Rolling Hills	SG	SG-F
	Rolling Hills Wind	SG	SG-FR

FERC ACCOUNT	DESCRIPTION	WIJAM	Modified Factors
Renewable Production Plant			
339	Renewable Plant		
	Geothermal	SG	SG-F
Other Production Plant			
340-346	Other Production Plant		
	Chehalis	CAGW	Situs - WA
	Hermiston	CAGW	Situs/System-Non-WA
Unclassified Production Plant			
106.3	Unclassified Production Plant	SG	SG-F
General Plant			
389 - 398	General Plant	SO	SO
Total Rate Base Additions			
22841	Accum Misc Oper Provisions - Other	CAGW	Situs - WA
282	Accumulated Deferred Income Taxes		
	Production	SG	SG-F
		SO	SO
	JB 1&2	JBG	SG-F
	JB 3&4	JBG	System - Non-WA
	Colstrip 4	CAGW	System - Non-WA
	Chehalis	CAGW	Situs - WA
	Hermiston	CAGW	Situs - Non-WA
	Rolling Hills Wind	SG	SG-FR
Production Plant Accumulated Depreciation			
108SP	Steam Prod Plant Accumulated Depr		
	Colstrip 4	CAGW	System - Non-WA
	JB 1&2	JBG	SG-F
	JB 3&4	JBG	System - Non-WA
108HP	Hydraulic Prod Plant Accum Depr	SG	SG-F
108XP	Solar Plant - Accumulated Depr	S	Situs
108WP	Wind Plant - Accumulated Depr		
	Wind - Except Rolling Hills	SG	SG-F
	Rolling Hills Wind	SG	SG-FR
108RP	Renewable Plant - Accumulated Depr		
	Geothermal	SG	SG-F
108OP	Other Production Plant - Accum Depr		
	Chehalis	CAGW	Situs - WA
	Hermiston	CAGW	Situs/System-Non-WA
General Plant Accumulated Depreciation			
108GP	General Plant Accumulated Depr	SO	SO
Accumulated Provision for Amortization			
111GP	Accum Prov for Amort-General	SO	SO
111HP	Accum Prov for Amort-Hydro	SG	SG-F
111IP	Accum Prov for Amort-Intangible Plant	SO	SO