–BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH–

In the Matter of Rocky Mountain Power's for Approval of the 2026 Inter-Jurisdictional Cost Allocation Protocol	))))))))	**Docket No. 25-035-47** **Exhibit No. DPU 1.0 DIR** **Direct Testimony of Matt Pernichele**

Redacted

FOR THE DIVISION OF PUBLIC UTILITIES

DEPARTMENT OF COMMERCE

STATE OF UTAH

Direct Testimony of

Matt Pernichele

February 5, 2026

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LIST OF ACRONYMS AND ABBREVIATIONS

2020 Protocol	2020 PacifiCorp Inter-Jurisdictional Allocation Protocol
Commission	Utah Public Service Commission
Company	PacifiCorp dba Rocky Mountain Power
Daymark	Daymark Energy Advisors, Inc.
Discarded Assets	Generation recently removed from Washington's allocation
Division or DPU	Utah Division of Public Utilities
GHG	Greenhouse Gas
NPC	Net Power Cost
PAC-E	PacifiCorp Balancing Authority Area East
PAC-W	PacifiCorp Balancing Authority Area West
Proposed 2026 Protocol	PacifiCorp's proposed allocation protocol
Washington 2026 Protocol	Washington's approved 2026 allocation protocol
Washington CCA	Washington Climate Commitment Act
Washington CETA	Washington Clean Energy Transformation Act
Washington Commission	Washington Utilities and Transportation Commission
WIJAM	Washington Inter-Jurisdictional Allocation Methodology
WCA	West Control Area Inter-Jurisdictional Allocation Methodology

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matt Pernichele. My business address is 160 East 300 South in Salt Lake City, Utah.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Utah Division of Public Utilities as a Utility Technical Consultant.

Q. PLEASE PROVIDE YOUR EDUCATION AND RELEVANT WORK EXPERIENCE.

A. I have worked for the Utah Division of Public Utilities for two and a half years. During this time, I have analyzed a variety of issues arising from the operation of regulated natural gas and electrical utilities. I was responsible for the Division's analysis and Phase II Testimony related to cost of service and rate design in Rocky Mountain Power's and Enbridge Gas Utah's most recent rate cases. I attended The New Mexico State University's Center for Public Utilities Practical Regulatory Training Class in 2023. I have JD and an MBA from the University of Utah.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the findings and recommendations of the Division and its consultant Daymark from its review of PacifiCorp's application for approval of its Proposed 2026 Protocol. Daymark also will be filing its own testimony in this docket.

Q. PLEASE INTRODUCE YOUR CONSULTANT.

A. The Division hired Daymark with Timothy Lenell as the lead consultant. Daymark is a Massachusetts-based consulting firm founded in 1980 with experience in detailed analyses of energy and environmental performance of electric systems, economic planning for transmission and distribution, and market analytics.

Q. PLEASE BRIEFLY SUMMARIZE THE WORK AND INVESTIGATIONS THAT YOU HAVE PERFORMED IN THIS MATTER.

A. The Division relied on information provided in PacifiCorp's application and direct testimony, answers to data requests, technical conferences, discussions with the Company, and discussions with the Division's consultants to arrive at its conclusions.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. The Division recommends that the Commission reject the Proposed 2026 Protocol as presented by the Company in its application and continue to use the 2020 Protocol but add to Utah's allocation any unallocated thermal generation plant assets discarded by Washington due to its legislated obligation to remove these assets from Washington's allocation by December 31, 2025.

The Division's evaluation finds that the Proposed 2026 Protocol's removal of the Chehalis generating facility from Utah's allocation unfairly and unreasonably increases Utah customers' exposure to expensive and volatile hedges and imposes other risks. The Proposed 2026 Protocol does not address or resolve important issues including the long-term effects of its allocation changes to resource adequacy, does not establish safeguards to prevent Utah from absorbing disproportionate decommissioning costs of retiring generation assets, and less accurately reflects cost causation than the 2020 Protocol. Finally, the proposed changes to the SO factor are unsupported by analysis and unapproved by previous proceedings.

To the extent that I do not address a specific issue, position, or proposal does not signify my agreement or disagreement with that issue, position, or proposal.

Q. WHAT CHALLENGES HAS THE DIVISION EXPERIENCED IN ITS REVIEW OF THE COMPANY'S PROPOSED 2026 PROTOCOL?

A. The Company's 2026 Protocol application was filed August 5, 2025, with a requested effective date of January 1, 2026. The Utah filing was over 4 months later than the Company's associated separate protocol filing with the Washington Commission, providing considerably less time for the Division's review in this proceeding. In this docket, the Company provided very little information on the separate Washington agreement requiring the Division and other Utah parties to rely on discovery to request information on the Washington protocol and other missing key information and necessary corrections, as discussed below.

Generally, the Company was responsive, responding within the scheduled discovery time frame, but still was not as generous with its information as the Division would hope given the complexity of its application and the Company's requested short time frame. This necessitated follow-up requests and delays in getting important information. For example:

On December 26, 2025, the Division sent data request set 9 to the Company, which included the following request as DPU DR 9.3(b):

> Ms. McCoy states that the revenue requirement impact calculation "does not contemplate certain state-specific regulatory adjustments" (line 98) and further indicates that the calculation will be refined prior to a deferred accounting request. Please identify all cost categories that the Company anticipates, including in a future deferred accounting request related to the implementation of the 2026 Protocol and describe how such costs would be allocated to Utah.

On January 9, 2026, the Company filed the following response:

> PacifiCorp objects to this request as overly broad, unduly burdensome, requesting the creation of a new report or analysis, requesting information that is not in the Company's possession or control, and not reasonably calculated to lead to the discovery of admissible evidence. Information related to the specific

revenue requirement for each jurisdiction will be calculated and provided in the applicable proceeding.[1]

On December 31, 2025, the Company filed with the Commission its application for a deferred accounting order regarding the 2026 Interjurisdictional Allocation Protocol in Docket No. 25-035-69. In this application, the Company estimated the Proposed 2026 Protocol costs assigned to Utah at $15.3 million plus interest.[2]

The Division sent DPU DR 11.1 to the Company,[3] requesting an explanation of the relationship between the $15.3 million estimated in the Company's deferred accounting application and the Utah 2026 Protocol revenue requirement amount. In response to this request, the Company confirmed that $15.3 million was ultimately the answer to DPU DR 9.3(b). It is unclear why the Company did not provide this amount in its initial response, as this amount was calculated at least 9 days earlier. It is also unclear why the Company considered the Division's request as "unduly burdensome, requesting the creation of a new report or analysis, requesting information that is not in the Company's possession or control." Furthermore, it took the Division's follow-up data request to receive this response when the Company should have supplemented its earlier response with the allegedly new information.

In addition to its discovery requests, the Division noted that there were multiple questions posed by the Utah Large Customer Group that were insufficiently answered. These are discussed below.

[1] DPU Ex. No. 1.1.
[2] *In the Matter of the Application for a Deferred Accounting Order Regarding the 2026 Inter-Jurisdictional Allocation Protocol,* Docket No. 25-035-69, Application for a Deferred Accounting Order at 6: ¶ 14 (December 31, 2025).
[3] DPU Ex. No. 1.2.

HISTORICAL FRAMEWORK AND LEGAL CONSIDERATIONS

Q. WHAT IS THE ALLOCATION PROTOCOL?

A. An allocation protocol is a mechanism to divide the economic costs and benefits of the Company's system between the states it serves.[4] It is an accounting tool and determines what the Company calls the "ratemaking position." [5] An allocation protocol does not determine how the Company delivers electrical service to customers or which customers get served by which assets in the physical world. The Company refers to this as the "operational position."[6] For example, if the 2020 Protocol allocates Utah 44.12% of Chehalis for a given year, it does not mean that 44.12% of the electricity produced by Chehalis goes to Utah customers in this example none of it will. But Utah customers will receive an amount of electricity equal to 44.12% of Chehalis' production from the system and pay 44.12% of the costs associated with operating Chehalis. The allocation changes Utah's ratemaking position. It does not change the operational position; the actual functioning of how the Company operates in the physical world.

Q. WHEN WAS THE 2020 PROTOCOL EFFECTIVE?

A. The 2020 Protocol was adopted by the Commission in its Order on April 15, 2020, in Docket No. 19-035-42. The 2020 Protocol had an interim period which started on January 1, 2020, and was to last until the earlier of the resolution of all remaining issues or December 31, 2023. The expiration date was extended to December 31, 2025, in Docket No. 23-035-20.[7] The Company was aware of the expiration terms of the 2020 Protocol and at the Company's request the Commission extended the 2020

[4] Direct Test. of Rick T. Link (August 5, 2025) at 6: 94 – 103.
[5] Confidential DPU Ex. No. 1.8 at 108: 109: 4 – 12.
[6] *Id.*
[7] *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) at 4.

Protocol until December 31, 2025.[8] This is the date that Oregon law mandated the removal of all coal plants from the allocation of utilities serving the state.9

Q. WHAT ALLOCATION METHOD HAS PREVIOUSLY BEEN USED FOR WASHINGTON?

A. The WIJAM was included as Appendix F, Washington Inter-Jurisdictional Allocation Methodology Memorandum of Understanding, in the 2020 Protocol.[10] The WIJAM superseded the WCA, utilized by Washington prior to the adoption of the 2020 Protocol.

Q. WHEN DID THE COMPANY SUBMIT ITS WA 2026 PROTOCOL?

A. The Company submitted its 2026 Washington Protocol to the WA Commission on April 1, 2025, as part of a power cost only rate case.[11]

Q. WHAT IS THE STATUS OF THE WA 2026 PROTOCOL?

A. On December 22, 2025, the Washington Commission issued its order accepting the Washington 2026 Protocol with an effective date of January 1, 2026.[12]

Q. WHAT IS THE CURRENT METHOD USED TO ALLOCATE COSTS FOR STATES OTHER THAN WASHINGTON?

A. There is no current method for Utah because the 2020 Protocol expired on December 31, 2025. However, the 2020 Protocol is the most recent method approved by the Commission.

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[8] *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 (July 27, 2023).
[9] This mandate originates from Washington Senate Bill 5116 (2019), codified as **RCW 19.405.030**, which states that "[o]n or before December 31, 2025, each electric utility must eliminate coal-fired resources from its allocation of electricity."
[10] Docket No. 19-035-42, Application, Ex. F (December 3, 2019).
[11] *Washington Utilities and Transportation Commission v. PacifiCorp d/b/a Pacific Power& Light Company,* Docket No. UE-250224.
[12] *See, DPU Ex. No. 1.9.*

Q. WHEN DID THE COMPANY SUBMIT ITS PROPOSED 2026 PROTOCOL IN UTAH?

A. The Company submitted its application on August 5, 2025, in Utah, months after filing its allocation proposal with the Washington Commission. While it appears that the Company could have filed its Proposed 2026 Protocol in Utah sooner, it chose not to.

Q. WHY HAS PACIFICORP MADE THIS PROPOSAL NOW?

A. In 2023, PacifiCorp requested that the 2020 Protocol be extended until the end of 2025.[13] The Company explained that it filed this docket in response to the expiration of the 2020 Protocol, the failure of multi-party negotiations,[14] failure to recover some costs, and a statutory deadline in Washington.[15]

The Washington CCA[16] was enacted in 2021. Among the Washington CCA's provisions to decrease greenhouse gas emissions, is the Washington CCA's mandate the removal of coal plant generation from Washington's ratemaking allocation by December 31, 2025. In accepting Washington's new allocation, the Washington Commission found the Company's efforts to prepare for the state's coal ban under the previous WIJAM allocation drove up prices to Washington consumers "by an overreliance on the market, stemming from a failure to procure sufficient resources over the past 15 years."[17]

The Company also mentioned its inability to recover costs that the Utah Commission deemed to be imposed by other states.[18] Among those costs were approximately $13 million for Washington CCA allowances for the Chehalis gas plant in

[13] *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).
[14] Docket No. 23-035-20, Rocky Mountain Power's Notice (July 11, 2024) in which the Company terminated negotiations in the Framework Issues Workgroup.
[15] Direct Test. of Michael G. Wilding (August 5, 2025) at 2:46-51.
[16] RCW 70A.65.
[17] DPU Ex. 1.9 at 23 § 73 quoting TEP Reply Brief, at § 1.
[18] Direct Test. of Cindy A. Crane (August 5, 2025) at 4:86 – 95.

Washington.[19] The Commission disallowed those costs because they are a state-specific initiative that should be allocated to the state causing the costs under the 2020 Protocol and they are discriminatory because they impose costs on Utah ratepayers that are not charged to Washington ratepayers.[20]

The existence of the known expiration date leads the Division to wonder why the Proposed 2026 Protocol was filed so close to the 2020 Protocol's expiration date.

Q. WHAT STANDARDS SHOULD THE COMMISSION USE TO EVALUATE THE PROPOSED 2026 PROTOCOL?

A. Utah statutes and previous Commission orders provide good guidance both for what Utah law requires and what is good policy for approving a new multi-state allocation protocol for PacifiCorp.

Historically, the Commission sought to meet its statutory and policy goals by having a Rolled-In solution as a goal. In a prior docket addressing inter-jurisdictional costs, the Commission's described the Rolled-In allocation method:

> *Generally, the Rolled-In method apportions costs and revenues among PacifiCorp's jurisdictions based on single utility system, fully rolled-in embedded cost-of-service analysis which is reflective of current system operations, and apportions these costs to customers based on cost causation. Typically, cost apportionment methods directly assign the costs of facilities which are not shared to the users of the facilities, and allocate shared costs and the costs of joint-use facilities among users of the facilities.*[21]

[19] Direct Test. of Cindy A Crane (August 5, 2025)
[20] *Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 24-035-04, Order at 47, 48 (April 25, 2025).
[21] *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues,* Docket No. 02-035-04, Report and Order at 3 (February 3, 2012).

The Rolled-In method seeks to maximize efficiency and minimize the costs of the utility by running it as a single, integrated system.[22]

Q. WHY HAS PACIFICORP'S PROPOSED 2026 PROTOCOL MOVED AWAY FROM A ROLLED-IN METHODOLOGY?

A. The Company has been moving away from a Rolled-In allocation method for quite some time. The Washington 2026 Protocol has accelerated this move. The straightforward Rolled-In method has become more problematic as states have enacted laws which may impose significant costs on PacifiCorp's whole system and have led to diverging resource preferences. Company witness Cindy Crane states that numerous state laws made it "increasingly challenging" to operate the system as an integrated whole.[23] Statutes that have been accused of imposing such costs include the Washington CETA,[24] and Washington CCA (mentioned above), Utah's Energy Independence Amendments,[25] Energy Security Amendments, and Utah's State Energy Policy,[26] and Oregon's Elimination of Coal-Fired Resources from Allocations of Electricity,[27] and Power Generation from Fossil Fuels.[28] These divergent policies argue against the Rolled-In method because they make it much more difficult and complex to accurately determine cost causation and risk penalizing one state's customers for another states' policies.

PacifiCorp's Proposed 2026 Protocol is in part an effort to insulate itself from the costs and risks of state-imposed costs by moving away from the Rolled-In methodology and separately allocating certain assets, costs, and benefits to Washington. This is not necessarily an objectionable goal but the Company's

[22] *In the Matter of a Proceeding to Establish an Allocation Methodology to Separate PacifiCorp's Assets, Expenses and Revenues Between Various States*, Docket No. 97-035-04, Report and Order at 2 (April 16, 1998).
[23] Direct Test. of Cindy A. Crane (Aug. 5, 2025) at 7-8:134-56.
[24] RCW 19.405.
[25] Utah Code § 54-17-1002.
[26] Utah Code § 79-6-301.
[27] Or. Rev. Stat. § 757.518.
[28] Or. Rev. Stat. § 469.413.

proposed method of achieving it is deeply flawed because the allocation does not reflect the system's actual operational position. The Company's proposed method is decreasingly cost causative, especially with more fixed allocations. This is discussed below and in Mr. Lenell's Direct Testimony.

Q. IS THE CURRENT ABSENCE OF AN ACTIVE ALLOCATION PROTOCOL A PROBLEM FOR THE CONTINUED OPERATION OF THE UTILITY?

A. Not necessarily. The absence of a formal protocol does not necessarily impede the Company's ability to operate or provide safe, reliable service. Under the Commission's current administrative rules, the Company's filing should default to the allocation methods used in its last general rate case.[29] While this creates a level of regulatory uncertainty, the Company is still entitled to seek a fair rate of return through standard ratemaking processes and the Commission is still mandated to set just and reasonable rates.[30]

Q. DOES THIS UNCERTAINTY CREATE A RISK THAT THE COMPANY WILL NOT ACHIEVE FULL COST RECOVERY?

A. Yes, it is possible that if different states adopt conflicting allocation methods, the Company may recover less than 100% of its total system costs.[31] This is true both with and without a common allocation protocol. In fact, as noted above, Washington has already been using a different allocation method for a considerable time.

Q. WAS THIS SCENARIO CONTEMPLATED BEFORE?

A. Yes. In the 1988 merger, the Company agreed to merger condition 11 which states that "The Merged Company shall agree that PacifiCorp shareholders shall assume all risks that may result from less than full system cost recovery if inter-divisional

[29] Utah Admin. Code R746-700-20.
[30] Utah Code § 54-4-4.
[31] DPU Ex. No. 1.3 PacifiCorp Response to UTLCG DR 3.4(d) – The Company has had a shortfall for many years because of Washington disallowing east side thermal resources in their rates although receiving the benefits of dispatchable generation.

allocations methods differ among the Merged Company's various jurisdictions."[32] This is a pre-existing legal obligation the Company voluntarily accepted and was a foundational piece of the 1988 merger. It is a long-standing agreement that shareholders, not Utah ratepayers, bear the risk of disparate state laws.

Q. DID THE COMPANY EXPECT ALL OF THE STATES IN WHICH IT OPERATES TO HAVE THE SAME PROTOCOL?

A. No. The Company submitted a separate 2026 Washington Protocol that is different than what was submitted in its other states. If the Company wanted to have the same protocol, it would, at a minimum, submit the same thing in each state, and at the same time. Even then, the state Commissions issue orders that do not align with a common allocation protocol.

Q. IS WASHINGTON'S PROPOSED ALLOCATION OF SYSTEM RESOURCES FAIR TO OTHER STATES SERVED BY PACIFICORP?

A. The Proposed 2026 Protocol creates clear winners and losers. Washington's costs decrease and the other states' costs increase relative to the 2020 Protocol.[33]

The Company has not met its burden of proof to show that the disparate impact of the Proposed 2026 Protocol is just reasonable, fair, and in the public interest. The Proposed 2026 Protocol introduces no new resources or efficiencies but instead decreases Washington's overall costs while increasing costs to the other 5 States.[34] This is due, at least in part, to the Chehalis plant being fully assigned to Washington despite Utah's ratepayers investing in the plant as a reliable, dispatchable resource and paying for its construction through depreciation expenses for many years.

[32] Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. (to be renamed PacifiCorp), Authorizing the Issuance of Securities, Adoption of Tariffs and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith, Docket 87-035-27, Report and Order (September 28, 1988) at. 97.
[33] *See,* RMP Attachment 1, SEM Workpapers, Summary tab (August 5, 2025).
[34] Id.

The Washington Commission found that "the record evidence supports a finding that situs assigning the Chehalis plant to Washinton will result in avoiding higher cost market purchases, generating revenue through market sales, and meeting future resource adequacy requirements."[35] Washington was allocated more generation than it previously had, leaving less for the other 5 states and thus shifting higher price market purchases and resource adequacy costs to the other 5 states while decreasing their potential market sales.

In its Washington filing, the Company explains that Washington is seeing more benefits than others from the proposed 2026 Protocol because [redacted]

As a result of the Washington Commission's approval of the filing, Washington's resource adequacy and ratemaking positions are significantly improved even though it has vacated its shares of coal facilities. The Proposed 2026 Protocol improves the ratemaking position for Washington without any actual changes to its operational position.[37] Denying the Proposed 2026 Protocol protects Utah's ratemaking position and prevents Utah ratepayers from paying more than they should under ratemaking principles.

Any determination on the fairness and reasonableness of the Proposed 2026 Protocol should include a detailed analysis of the ratio of power from hedging purchases to total electricity consumption allocated to each state. Given that hedged power is typically more expensive and subject to greater price volatility, the Commission must understand these cost-benefit allocations across the entire system

[35] DPU Ex. No. 1.9 at 88, ¶ 308.
[36] *CONFIDENTIAL DPU Ex. 1.8* at p. 15 - 17.
[37] Id at 109: 5-17.

to make an informed judgement. This foundational data should serve as the basis for any subsequent modifications or accommodation for state policies or whatever else the Commission deems appropriate. Resource choices, and attendant costs, made over the past few decades should not be so readily undone by an allocation change made to accommodate one state's policy imperatives. Washington's portfolio should be supplemented with resources to backfill lost capacity and not simply wrested from other states' allocations.

Q. SHOULD ALL STATES ON THE SYSTEM ALWAYS BE ALLOCATED A SIMILAR PERCENTAGE OF EXPENSIVE MARKET PURCHASES?

A. Not necessarily. If a state's policies or regulatory environment result in a failure to develop sufficient generation to meet its own load requirements, that state should be responsible for the incremental cost of the market purchases necessary to bridge the resulting gap.

Similarly, if a state bans allocations of fossil fuel based or GHG emitting generation, it should not necessarily be allocated larger percentages of the system's non-emitting generation. All states on the system have approved, relied upon, and paid for their portions of the costs of the Company owned generation under previous planning regimes. It is unfair and unreasonable for the Company or any state to unilaterally reallocate major assets, and thus their costs and benefits. Such unilateral actions are also likely to be disallowed by commissions in other states. Any state that has a capacity shortfall because of its own state policies should be allocated the resulting costs. To share those costs with other states would not be fair or reflect cost causation principles. It is true that Utah ratepayers are not paying for Washington CCA allowances previously required to be purchased for Chehalis' generation. But two key points bear remembering: first, Washington is apparently now slated to fully cover Chehalis generation with free allowances,[38] and second,

[38] RCW 70A.65.120 directs the Washington Department of Ecology to distribute no-cost allowances to qualifying electric utilities to mitigate the cost burden of the cap-and-invest program on Washington customers.

Utah ratepayers are not obligated to pay a tax that violates federal law on discriminatory electricity taxes.[39] Utah ratepayers should not lose their share of a valuable asset because of another state's discriminatory law or the utility's desire to minimize ratepayer impacts in that state, which made the affirmative decision to redesign its electrical generation portfolio.

Q. ARE THERE ANY COSTS RESULTING FROM STATE POLICIES THAT SHOULD BE CONSIDERED?

A. Yes. The policies mentioned in the discussion of a Rolled-In allocation could all potentially increase the Company's cost of serving its customers. These include Utah's recently enacted laws,[40] which have been criticized as possibly keeping coal and natural gas plants running after they have become non-economic. But of more immediate relevance are PAC-W state policies that have long prevented the construction of GHG emitting generation in those states and more recent policies that have banned the allocation of GHG emitting generation to customers in those states. The Company's proposal explicitly defers questions on future resource choices to a subsequent phase of allocation discussions and decisions.

Q. WHAT STATE POLICIES HAVE PREVENTED THE CONSTRUCTION OF GHG EMITTING GENERATION?

A. The PAC-W states, Washington, Oregon, and California, have all enacted various laws that made it exceptionally difficult, at best, to build new CO2-emitting generation in those states. Among these policies is California's increasingly strict emissions standards for baseload generation[41] and strict limitations on repowering existing plants.42 Oregon has banned siting permits for all fossil fuel-based generation without 100% carbon capture43 and codified this ban in regulations

[39] 15 U.S.C. § 391.
[40] S.B. 224, 65th Leg., 2024 Gen. Sess.
[41] CA Pub. Util. §§ 8340-8341.
[42] CA Pub. Util. §§ 2900-2913.
[43] Or. Rev. Stat. § 469.413.

explicitly banning all fossil generators.[44] Washington enacted the Washington CCA, which requires GHG-emitting generators in the state to purchase allowances at auction and gradually phasing out the allowances by 2045. To be sure, federal regulatory pressure has mattered as well. But the Division has consistently raised the issue of the Company's failure to model natural gas generators in integrated resource planning.[45] The Company has bent its planning processes to accommodate PAC-W resources preferences and now seeks to insulate Washington from the cost of those decisions by fully allocating the Chehalis plant to it. In a recent IRP public input meeting the Company provided that it had "invented a non-emitting peaking resource in the 2021 IRP because we weren't allowed to have gas." [46] This quote was connected to a discussion on Oregon House Bill 2021 and GHG-emission concerns.

Q. HOW COULD THESE POLICIES AFFECT UTAH RATEPAYERS THROUGH PACIFICORP'S MULTI-STATE ALLOCATION?

A. These policies have made it difficult to build enough generation in PAC-W to serve the existing load there. The PAC-W states have been allocated significant generation in PAC-E and neighboring territory. In various dockets, the Division has asked for information concerning PacifiCorp transmission assets sufficient to evaluate the extent to which power can be moved between PAC-E and PAC-W in quantities roughly matching allocations. Given the lack of sufficient information, the Division concludes the Company does not possess or lease sufficient transmission capacity for the PAC-W states to fully use the energy allocated to them from PAC-E generation. The Company has admitted that [redacted]

[44] Or. Rev. Stat. § 345-024-0500.
[45] In his Direct Testimony, Division witness David Williams noted that "in the 2021 IRP, the Division requested that the Company run a sensitivity where new natural gas plants were allowed. This resulted in the S-04 sensitivity, described in '2021 IRP – Supplemental Sensitivity Modeling Results' which was filed on the RMP website." Williams Direct Test. at 25:564-67. The sensitivity is available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/PacifiCorp_2021_IRP_Sensitivity_Cases.pdf (p. 5).
[46] PacifiCorp, *2027 IRP Public Input Meeting: Day 1/4 - Part 1*, YouTube, at 1:30:04 (Jan. 28, 2026), https://www.youtube.com/watch?v=pG86FH4RF4U.

[redacted][47] Building sufficient transmission to move the required electricity from PAC-E to PAC-W would likely be a very expensive option and would still come with significant line losses. It is probably not the most efficient way to operate the Company's system.

Implicit in the idea of a Rolled-In allocation is the energy these PAC-W allocated assets generate is fungible with the rest of the energy on the western system so the excess generation physically located in PAC-E can be sold and the revenues from their sale can be used to buy the same amount of energy in PAC-W. The Proposed 2026 Protocol seems to also be based upon this assumption. This type of allocation may be accurate enough if the costs of acquiring power are similar throughout the system, but they are not. The vast bulk of forward market purchases, which is on average the system's most expensive electricity, is purchased at the Mid-Columbia power hub in Eastern Washington, for use in PAC-W.

The Washington Commission found in party testimony the statement "These bill increases were primarily driven by an overreliance on the market, stemming from a failure to procure sufficient resources over the past 15 years"[48] to be "correct".[49] "Instead of taking proactive steps to reduce its exposure to volatile market prices, the Company has simply used the Proposed 2026 Protocol to reallocate these inflated costs to other jurisdictions. State policies in PAC-W created this short operational position for the Company and attempting to remedy this shortfall by shifting costs to ratepayers in other jurisdictions seems unreasonable and unfair. "The Division has asserted for several years that Utah customers were unfairly paying for expensive

[47] Confidential DPU Ex. 1.8. at 56: 13 - 16 (September 17, 2025).
[48] DPU Ex. 1.9 at 23: ¶ 73, quoting TEP Reply Brief, at ¶3, 22-23.
[49] *Id.* at 26: ¶ 86.

hedges in PAC-W. The Proposed 2026 Protocol increases Utah's allocation of those purchases.

Q. WHAT STATE POLICIES HAVE PREVENTED ALLOCATIONS OF GHG-EMITTING GENERATION?

A. These same PAC-W states, California, Oregon, and Washington have all enacted various laws prohibiting the allocation of GHG emitting generation to utilities serving them. California has established an Emissions Performance Standard preventing its utilities from entering Power Purchase Agreements' with CO_2-emitting generators lasting over 5 years[50] and is reducing the amount of electricity that can be from these resource in stages to zero by the end of 2024.[51] Oregon has enacted increasingly strict emission caps that essentially phase out all CO_2 emissions from power generation by 2040 and mandated that utilities plan for non-emitting resources.[52] The Washington CETA, in addition to its January 1, 2026 coal ban, mandates that all electricity sold in the state be GHG neutral by 2030 and be from 100% non-emitting sources by 2045.[53] These policies have not only limited PacifiCorp's ability to build new resources, they have also likely limited the number and type of market resources the Company can contract for.

Q. HOW COULD THESE POLICIES AFFECT UTAH RATEPAYERS THROUGH PACIFICORP'S MULTI-STATE ALLOCATION?

A. Division witness Timothy Lenell explains how the Proposed 2026 Protocol's re-allocation of generation to accommodate the PAC-W state's laws could shift costs to Utah ratepayers because of the higher operating costs, shorter remaining service life, and much greater decommissioning costs. The policies mentioned above ban GHG-emitting generators from a state's allocation years before they ban, or attempt to ban, market purchases from GHG-emitting generators. A utility in PAC-W will be

[50] CA Codes Pub. Util. §§ 8340-8341.
[51] CA Codes Pub. Util. § 454.53.
[52] Or. Rev. Stat. § 469A.400-469A.475.
[53] RCW 19.405.

able to buy power from GHG-emitting generators on the market for years longer than it will be able to obtain the power from GHG-emitting generators through a Power Purchase Agreement or company owned plant in another state. Recent history clearly shows that when these market purchases are fixed hedges, they are likely to be significantly more expensive than the cost of power allocated from a Company owned plant or power obtained through a longer-term Power Purchase Agreement. The Proposed 2026 Protocol would allocate an even larger percentage of these costs to Utah ratepayers.

Q. CAN YOU RECONCILE SUGGESTING THAT UTAH MAINTAIN ITS ALLOCATION OF CHEHALIS WHILE REJECTING ADDITIONAL HEDGES, DESPITE BOTH RESOURCES PRIMARILY BEING PHYSICALLY IN PAC-W?

A. Yes. The fundamental issue lies in reconciling the proper application of cost causation principles. The Chehalis generating facility was originally approved as a system-wide resource, and Utah ratepayers have made significant investments over the years to secure the benefits of this reliable and dispatchable resource under PacifiCorp's long-running portfolio approach.

In contrast, the recent surge in expensive market hedges is primarily driven by a generation shortfall in PAC-W balancing area. This deficit is a direct consequence of policy choices in Oregon and Washington that have restricted generation and created a persistent imbalance between local resource generation and load. They have been applied in IRP processes even though states in PAC-E have no such restrictions, as noted in lines 326-334 above. While short-term market transactions are a necessary tool for daily system balancing, long-term reliance on expensive market purchases to cover a chronic shortfall in PAC-W is not a burden that should be shared system-wide. Requiring Utah ratepayers to fund these long-term hedges made in PAC-W effectively forces them to subsidize the legislative and policy mandates of other jurisdictions.

Q. IS THERE A FAIRER ALLOCATION OF NPC THAT WOULD MORE ACCURATELY REFLECT COST CAUSATION?

A. Potentially. PacifiCorp witness Rick Link mentioned that the Company's Phase 2 protocol proposal would include "a market settlement-based NPC allocation methodology."[54] PacifiCorp witness Michael Wilding explains that would largely keep allocate generation as it is now but would price electricity based on the market price at the location where the electricity is used.[55] Long term market prices could possibly be allocated to the states where the power is actually used in a similar way. It is not clear that locational marginal pricing would adequately compensate generation for its capacity values. These ideas have not been adequately addressed yet and should be explored in the future.

Q. IS WASHINGTON RESOURCE ADEQUATE?

A. No. Especially after removing coal. For WIJAM, according to the direct testimony of Mr. Michael G. Wilding, "[redacted]."[56]

When analyzing the energy needs in Washington, Mr. Wilding included the following chart and question and answer in testimony:

[54] Direct Test. of Rick T. Link (August 5, 2025) at 27: 539 – 546.
[55] Direct Test. of Michael G. Wilding (August 5, 2025) at 16: 286 – 303.
[56] CONFIDENTIAL DPU Ex. 1.8 at 5: 16-19.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] Even with the unreasonable full assignment of Chehalis, Washington does not have enough power. Going forward though, Washington will have its own hedge book, which is helpful, because the costs of market purchases in

[57] *Id.* at 10: 1-8

Washington will purportedly stay in Washington.[58] Exactly how that works is unclear. However, the biggest difference between the WIJAM and the Washington 2026 Protocol is how Chehalis is allocated. If Chehalis is 100% allocated to Washington, the "shortness" is now allocated to the other five states, which get saddled with more hedges and other market purchases.

It is still unknown how these final results will shake out. In fact, parties tried to gain greater clarity by asking RMP to run past years' actual results through the 2026 Protocol to allow parties to more concretely see its effects.[59] The Company refused to do the analysis. Accepting a new allocation method without this detail and without an expiration date is not in the public interest. No long-term analysis has apparently been completed at this time. The hedging program costs [redacted], and it is imperative to get the allocations correct.

The large gap in energy needs in Washington and how that gets handled is a concern between Washington and the Company. The Division recognizes the need in Washington, but the Company has been aware of these Washington laws since at least May 2019.[60] Instead of using hedges, the Company could have built generation able to serve PAC-W earlier to supply Washington with its energy needs. Utah does not need to fill the gaps and subsidize Washington due to Washington policy and the Company's own planning choices in the face of this Washington capacity cliff. There is no reason for Utah to give up capacity resources and swap them for market purchases. Indeed, such a result runs counter to the state's statutory energy policy. Utah Code mandates a preference for energy sources that are adequate, reliable, dispatchable, and affordable.[61] The Chehalis plant meets these criteria and foregoing Utah's share in it to move toward more market purchases may not be in harmony with Utah state energy policy.

[58] Direct Test. of Michael G. Wilding (August 5, 2025) at 14: 242 – 246.
[59] DPU Ex. 1.7.
[60] DPU Ex. No. 1.4.
[61] Utah Code § 79-6-301.

Q. ARE UTAH RATEPAYERS OBLIGATED TO RELINQUISH THEIR INTERESTS OF FORMERLY APPROVED SYSTEM GENERATION BECAUSE OF POLICY CHANGES IN THE STATE OF WASHINGTON?

A. No. Under the framework of multi-state utility regulation, Washington's policy shifts do not mandate a forfeiture of assets by Utah ratepayers. Each state retains sovereign authority over its jurisdictional resource mix. The Company is well aware that divergent state laws create disparate regulatory environments. As mentioned before, the associated risks of these different environments are fundamentally a shareholder responsibility, not a burden for Utah customers. While that burden absolutely bears on the Company's risk profile and the rates of return it might need to compensate its capital investors, it is not Utah's responsibility to balance the Company's books due to another state's choices.

Furthermore, if a state elects to divest from a specific resource, such as a coal-fired power plant, Utah is under no obligation to follow suit and divest of its beneficial share of those coal resources, nor is Utah required to absorb the discarded resources. Utah maintains the right to accept the vacated shares of any resource by other states without providing compensation for fully depreciated plant or paying depreciation or decommissioning costs that should have been paid by past users.

ALTERNATIVES TO THE PROPOSED 2026 PROTOCOL

Q. WHAT HAPPENS IF THE COMMISSION REJECTS THE PROPOSED 2026 PROTOCOL?

A. The Company stated it "will be forced to seek temporary extensions of the 2020 Protocol."[62] The Company is not forced to seek anything, as the 2020 Protocol was used in the last rate case, and the 2020 Protocol would be used again if the Company were to file for a rate case right now. As mentioned before, Utah Administrative Code R746-700-20 requires an Electrical Corporation base its general rate case filing on "allocation

[62] Rocky Mountain Power's Application for Approval of the 2026 Inter-Jurisdictional Allocation Protocol at 8 ¶ 16 (August 5, 2025).

methods used in the public utility's last general rate case proceeding or any allocation method subsequently approved by the Commission."

Furthermore, the Commission is not bound by a multi-state protocol whether it is approved or not. Utah Code section 54-4-4 legally charges the Commission to set rates that are just reasonable, and in the public interest. Whether rates are tied to an allocation protocol or not is irrelevant to the Commission's obligation. The Company has acknowledged this, testifying that "the Commission is not bound by the terms of the 2020 Protocol."[63] The benefits of a common allocation scheme to shareholders and ratepayers are one relevant factor among many in evaluating the public interest.

Q. COULD YOU PLEASE SUMMARIZE THE DIVISION'S POSITION ON THE PROPOSED 2026 PROTOCOL AND ITS ALLOCATION OF 100% OF THE CHEHALIS PLANT TO WASHINGTON?

A. The Division strongly opposes the allocation of 100% of the Chehalis generating facility to Washington. This proposal unfairly strips Utah ratepayers of a vital, dispatchable resource they have funded for years. The move is not supported by cost-causation principles or long-term analysis. Rather, it is a reactive measure to satisfy the policy priorities of a single state at the expense of other PacifiCorp states. It is also likely to be a reaction to other states' Commissions being unwilling to impose Washington CCA allowance costs, a discriminatory tax, on their ratepayers.

The Division has identified at least seven important points of objection to the Company's Proposed 2026 Protocol and the reallocation of the Chehalis plant exclusively to Washington.

[63] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Regulations,* Docket No. 25-035-04, Phase III Rebuttal Test. of Shelly E. McCoy, at 3: 64-65 (March 10, 2025).

1. Violation of Cost-Causation and Reliance Principles

The Chehalis facility was acquired and approved as a system-wide resource based on its dispatchability, reliability, market value, and long-term cost savings to all participating states. Utah customers have funded their share of the acquisition and financing costs based on these expected long-term benefits. Reassigning Chehalis now denies Utah the remaining value of an asset it has already paid a disproportionate share to secure, violating fundamental regulatory principles of cost-causation and investor/ratepayer reliance. Daymark witness Mr. Lenell addresses this further in his testimony.

2. Unilateral Transfer of Benefits and Risk

The proposed transfer moves the benefits of Chehalis—including dispatchability, price-spike protection, and market-sale opportunities—exclusively to Washington. Conversely, Utah and the remaining states are forced to absorb increased exposure to short-term market purchases and price volatility. The Company has failed to provide a binding hedge-reassignment framework or mitigation mechanism to offset this significant shift in risk.

3. Increased Long-Term Cost and Replacement Exposure

Chehalis' removal materially alters Utah's long-term resource mix, increasing reliance on aging coal units with shorter remaining useful lives. This accelerates future replacement timing and exposes Utah to higher long-term capital and fixed-cost obligations. Increased exposure to open market transactions and market risk. The Company provided no long-term analysis (beyond a short-term revenue snapshot) to quantify these impacts, despite proposing that the 2026 Protocol remain in effect indefinitely.

4. Asymmetric Treatment Compared to Coal Exit Protections

The 2020 Protocol included explicit safeguards and decommissioning responsibilities for states exiting coal resources. The 2026 Protocol lacks these protections. It allows Washington to exit its responsibility for Chehalis without retaining comparable legacy obligations, creating an asymmetric and unjustified cost shift to the remaining states.

5. Conflict with Utah Energy Policy

Under Utah Code section 79-6-301, the state prioritizes "adequate, reliable, and dispatchable" energy resources. The current allocation of Chehalis directly supports these goals. Removing this resource undermines Utah's energy policy in favor of Washington's discretionary policy preferences. Notably, while Washington's exit from coal is mandated by the WA CETA ,[64] the reassignment of Chehalis is not legally required, but is a Company-driven solution to address discriminatory carbon allowances.

6. Inconsistency with Prior Commission Approval

The Commission originally approved the Chehalis acquisition under a public-interest standard that emphasized system-wide benefits, dispatchability, and long-term cost minimization. Reallocating Chehalis without Utah’s affirmative consent contradicts precedent and undermines regulatory consistency and reliance interests.

7. Lack of Governance and Procedural Safeguards

The proposed Protocol is dangerously open-ended. It provides no specific criteria for when a system resource can be removed, requires no affirmative election by the

[64] Chapter 19.405 RCW.

affected states, and contains no expiration date. This leaves Utah ratepayers exposed to ongoing risk without meaningful oversight or recourse.

Q. IF UTAH RETAINS ITS SHARE IN CHEHALIS, WHAT ABOUT THE COMPLIANCE COSTS?

A. The Division is aware of the compliance costs associated with the Chehalis gas facility imposed by the WA CCA . The Company has previously sought to allocate these compliance costs across its entire system. The Commission, along with regulators in Idaho, Oregon, and Wyoming, have denied recovery of these costs because they represent state-specific mandates under the Washington CCA and are discriminatory.[65]

Under the Proposed 2026 Protocol, there are no compliance costs for Utah because of Washington's acceptance of the Washington 2026 Protocol, which assigns 100% of Chehalis to Washington.[66] However, this creates a potential oversubscription if Utah and other states do not voluntarily relinquish their shares, and it is unknown what happens in that situation.[67]

Q. CAN THE FIVE-STATE PARTIES ACCEPT THE DISCARDED ASSETS AND STILL REJECT THE PROPOSED 2026 PROTOCOL?

A. This is unknown. Washington was obligated to remove PacifiCorp's coal plants from its allocation. Rejecting the Proposed 2026 Protocol will not preclude Utah from taking its allocated share of the Discarded Assets.

[65] Or. Rev. Stat § 70A.65.
[66] DPU Ex. 1.5.
[67] DPU Ex. 1.6.

Q. WHY WOULD UTAH WANT TO ACCEPT THE DISCARDED ASSETS?

A. The Discarded Assets would be of value to Utah because Utah energy policy favors this type of generation and they would reduce the State's reliance on expensive and volatile market purchase, add capacity, and enhance reliability. In the Proposed 2026 Protocol, these assets are not assigned exclusively to Utah, but Utah receives a dynamically allocated share of them.

As noted above, Utah's state energy policy prioritizes resources that are adequate, reliable, and dispatchable[68] The coal generation that states have banned from their allocations fit these criteria very well. Increasing the allocation of these units to Utah would directly enhance Utah's generative capacity, bolstering its system adequacy. These plants have proven very reliable over the years as they have high capacity factors and few outages. Furthermore, because they are dispatchable, these facilities provide a constant power supply that is available on demand and can be curtailed and ramped up to support the intermittent nature of solar or wind resources. Solar and wind generation require dispatchable resources for reliability.

Utah's preference for these types of assets is expressed in other statutes as well. Utah Code creates a statutory framework designed to preserve the operation of "proven dispatchable generation resources" including favorable cost recovery provisions and a rebuttable presumption against closing.[69] And in 2024, the Utah Legislature enacted SB 161 giving the State the power to potentially prevent or delay the retirement of coal or gas generation[70] and force their sale.[71]

Benefits to the Five-State Portfolio and ultimately Utah customers of transferring the Discarded Assets to the shared Five-State Portfolio include:

[68] Utah Code § 79-6-301(1)(a)(ii).
[69] Utah Code § 54-17-1002.
[70] Utah Code § 11-13-318.
[71] Utah Code § 79-6-404(5)(d).

- Improved Resource Adequacy and Reliability. The retention of coal resources allows Utah to maintain a sufficient supply of energy to meet demand, particularly during peak periods.

- Reduced Market Reliance. The 2026 Protocol reduces the system energy shortfall over critical net peak demand hours, thereby reducing the Company's reliance on short-term market purchases.

- Improved Energy Position. The additional shares of the discarded portion of Washington's thermal plant improves Utah's energy position for all hours compared to the 2020 Protocol.

- Stability. This stronger resource position results in more price stability for customers.

- NPC Reduction. Recent history indicates that the increased energy cost from the coal plant generation would be less than the replacement power obtained through higher cost of market purchases.

- This analysis also underscores why Utah should resist surrendering its share of the Chehalis generation facility while proactively seeking increased allocations of coal and natural gas generation discarded by other jurisdictions. Utah's interest in these assets is rooted in the state's clear statutory preference for adequate, reliable, and dispatchable resources.

Q. WHAT IS THE COST TO UTAH RATEPAYERS FOR ACQUIRING THESE DISCARDED COAL ASSETS?

A. There is no direct acquisition cost. Utah is not required to provide compensation or give anything in return for these shares. Washington has voluntarily elected to discard these assets in order to comply with its own state mandates. Mr. Lenell raises issues concerning whether there is adequate coverage of decommissioning cost exposure. But generally, the Washington shares should be fully depreciated. As

a result, these shares are essentially unallocated and available for reclamation from other jurisdictions, which the Company would prefer so it is not under recovering.

While Washington is removing itself from the financial obligation of coal, including all associated costs and direct benefits, it continues to benefit from the physical presence of these dispatchable resources on the integrated system. Specifically, Washington realizes the diversity benefit of system reliability and the ability of these plants to provide operating reserves and ramping support as intermittent renewables fluctuate, all without contributing to the plants' fixed costs. [72]

The Division recommends the Commission accept the portion of these assets allocated to Utah in the 2026 Protocol with a few additional provisions

Q. WHAT ARE THE ADDITIONAL PROVISIONS?

A. It is unknown at this time what the closure and decommissioning costs will be and how they will be allocated. The Commission should protect Utah ratepayers from bearing an inequitable share of those costs for the time other states used and benefited from the plants. And if the coal plants are being used for reliability for the system, then that should be recognized as well. The system cannot function without dispatchable energy.[73]

TIMEFRAMES

Q. WHY IS DECEMBER 31, 2029, AN IMPORTANT DATE TO CONSIDER?

A. December 31, 2029, serves as the final day coal-fired resources that can be included in electricity supplied to Oregon customers as established by Oregon Senate Bill 1547, also known as the Clean Electricity and Coal Transition plan.

[72] CONFIDENTIAL DPU Ex. 1.8 at 11: 12 - 12: 4
[73] *Id.* at 12:15 – 13:20.

Q. WHY IS THIS AN IMPORTANT DATE FOR UTAH'S ALLOCATION CONSIDERATIONS?

A. Under Oregon's existing state policy any existing coal generation allocated to Oregon will need to be reassigned before January 1, 2030. If the Commission wishes to establish a new multi-state allocation protocol it should anticipate this date. The Division strongly recommends that the Company initiate workshops and collaborative meetings well in advance of 2030. Early engagement allows states and the Company to reach a consensus, if possible, on methodology outside of the high-pressure environment of an adjudicative. Providing this temporal runway potentially allows for a settled agreement. Should these good-faith negotiations fail, the Company would still have sufficient time for the formal adjudicative process and secure a final order by December 31, 2029. But, as evidenced by the current docket, using only the adjudicative process could lead to disparate outcomes across the various state jurisdictions. The Division is well aware of the difficulties in coming to a consensus among the states but feels the discussions among the states and Company are worthwhile.

Q. WHAT IS THE DIVISION'S RECOMMENDATION REGARDING THE DURATION AND EXPIRATION DATE OF A NEW ALLOCATION PROTOCOL?

A. The Division recommends that if a new allocation protocol is accepted, it should expire no later than December 31, 2029. It should not be structured as an indefinite proposal that persists until a successor is approved. The responsibility for the timely filing and approval of a successor protocol rests solely with the Company. If the Company desires the protection of a multi-state protocol, it must proactively secure the approval and implementation of a new allocation protocol before an active protocol expires.

It is important to note that a common allocation protocol is not a statutory requirement, but rather a discretionary mechanism sought by the Company to mitigate its own financial and regulatory risks, and their corresponding effects on

ratepayers. While the Company suggests that the Proposed 2026 Protocol should remain in effect until a replacement is approved, the Division strongly disagrees. There is also no justification for extending this protocol beyond when Oregon departs from coal-fired generation.

SO FACTOR

Q. PLEASE EXPLAIN THE DIVISION'S CONCERNS REGARDING THE COMPANY'S PROPOSED SYSTEM OVERHEAD (SO) ALLOCATION FACTOR.

A. The Company's proposed weighting of the SO Factor utilizes a one-third weighting of System Capacity (SC), System Energy (SE), and System Generation Plant (SGPD) factors. The Division is concerned that the SO Factor lacks any supporting quantitative analysis. In response to DPU Data Request 9.4, the Company admitted that there are "no analyses, studies, work papers or other documents" available to support this methodology.[74]

Q. HOW DOES THE COMPANY JUSTIFY THIS SPECIFIC ALLOCATION METHODOLOGY?

A. The Company asserts that this methodology was outlined as a "Resolved Issue" in Section 5.4 of the 2020 Protocol. Because it was previously identified as a resolved issue, the Company chose to include it in the Proposed 2026 Protocol without further justification.

Q. DOES THE DIVISION AGREE THAT THIS ISSUE WAS FULLY RESOLVED AND READY FOR IMPLEMENTATION?

A. No. The 2020 Protocol was an interim agreement. The implementation of any "Resolved Issues" from the 2020 Protocol was explicitly contingent upon resolving broader "Framework Issues" and the Resolved Issues would only take effect in the "Post Interim Period." In Docket No. 19-035-42, Division witness Dr. William "Artie" Powell testified that the final implementation of the Resolved Issues was "contingent

[74] DPU Ex. No. 1.10

on resolving the Framework Issues discussed in Section 6" and that the development of a Post-Interim period allocation method based on those resolutions.[75] The Framework Issues were never resolved and the Post Interim Period never began so the Resolved Issues were never approved to be implemented by either the parties or the Commission.

Q. WHAT IS YOUR CONCLUSION REGARDING THE PROPOSED SO ALLOCATION FACTOR?

A. Since a post-interim period method was never agreed upon and the underlying framework issues remain unresolved, the SO method mentioned in the 2020 Protocol was never formally approved for long-term use. It would be premature for the Commission to approve this methodology that the Company admits has no supporting analysis or workpapers.

CONCLUSION

Q. PLEASE PROVIDE THE DIVISION'S FINAL COMMENTS AND RECOMMENDATIONS

A. The Division recommends rejecting PacifiCorp's proposed 2026 Protocol as filed. PacifiCorp's proposal unfairly increases Utah's risk and financial exposure by removing the Chehalis natural gas facility from Utah's allocation and passing on some of the cost of other states policies to Utah ratepayers. Any costs of complying with Washington's laws should not be an obligation on Utah ratepayers. The Company's allocation proposed in its application is less cost causative than the existing arrangement and does not reflect the real world, operational position, which remains unchanged by the Proposed 2026 Protocol. The Company's proposed SO factor lacks any support and has not been approved in prior cases. However, Utah should accept the allocation of any of Washington's discarded coal assets if they become available.

[75] *Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 19-035-42, Direct Test. of William "Artie" Powell (Feb. 25, 2020) at 17:354-57, 18:391-93.

The Division's consultant, Tim Lenell's, testimony discusses the lack of support and analysis indicating the long-term impacts of the Proposed 2026 Protocol. Mr. Lenell illustrates the various risks and costs imposed by the situs assignment of the Chehalis plant and other gas fired generation to Washington in exchange for the other 5 states being allocated Washington's ratemaking position of coal generation. He concludes that these risks eroding Utah's resource adequacy position, make Utah dependent on a smaller pool of resources, and add more risky and volatile market purchases to Utah's rates. He provides strong evidence that Utah risks paying higher decommissioning and replacement costs from its larger allocation of aging coal plants and argues for a sunset provision should the Proposed 2026 Protocol be accepted.

The Division acknowledges that the Company deserves the opportunity to earn the rate of return authorized by the Commission. Statutes and regulations enacted by Washington, Oregon, and California and their conflict with Utah's policies make this more difficult. This situation will become more complex as the PAC-W states implement future restrictions on GHG emitting generation from laws that they have already passed. But Utah policy, Commission precedent, and commonly accepted regulatory principles prohibit the costs of these policies from being imposed on Utah's ratepayers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.