BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of Application of Rocky Mountain Power for Approval of the 2026 Inter-Jurisdictional Cost Allocation Protocol	Docket No. 25-035-47

DIRECT TESTIMONY

AND EXHIBITS

OF

JEFFREY K. LARSEN

SUBMITTED ON BEHALF OF THE

UTAH LARGE CUSTOMER GROUP

February 5, 2026

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeffrey K. Larsen. My business address is 524 East 700 South, Centerville, Utah, 84014. I am the owner and sole employee of JKL Consulting Services, LLC.

Q. BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received a Master of Business Administration degree from Utah State University in 1994 and a Bachelor of Science degree in Accounting from Brigham Young University in 1985. I have also participated in various post-graduate training and education programs through the Wharton School and the J.L. Kellogg School of Management at Northwestern University. In addition to formal education, I have also attended various educational, professional, and electric industry-related seminars over the course of my career.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND CAREER.

A. Most of my career was spent with PacifiCorp or one of its predecessor companies, Utah Power & Light Co. ("Utah Power" or "UP&L"), from 1985 to 2019. Over that career, I worked in various positions and levels of management in financial accounting, regulation, compliance, government affairs, and strategic planning. In 2013, I led the state approval process for the acquisition of NV Energy by Berkshire Hathaway Energy, Inc. After that approval, I was appointed to the NV Energy Board of Directors in 2014 and served until retirement. Starting in 1987, I worked on the first interjurisdictional cost allocation issues between Utah Power and PacifiCorp[1] and have been involved in the allocation process in

[1] At the time of the merger, PacifiCorp was doing business as ("DBA") Pacific Power and Light ("Pacific Power" or "PP&L"). Post merger, PacifiCorp retained the two DBAs of Pacific Power and what is now known as Rocky Mountain Power ("RMP") (formerly Utah Power & Light Co.). References to "PacifiCorp" or the "Company" mean the post-merger entity, references to Pacific Power or PP&L mean the operating division for the states of Oregon, Washington, and California, and references to RMP mean the operating division for Idaho, Utah, and Wyoming.

the decades since then. The majority of my time at PacifiCorp was spent with the Regulation Department. I retired as a senior vice president of strategic business planning for PacifiCorp in December 2019. Since retirement, I have provided limited consulting services to clients related to utility issues from 2021 to the present.

Q. PRIOR TO YOUR RETIREMENT, WERE YOU INVOLVED IN THE DEVELOPMENT OF THE 2020 PROTOCOL ON BEHALF OF THE COMPANY?

A. Yes. I successfully led the negotiations on behalf of PacifiCorp that resulted in the adoption of the 2020 PacifiCorp Inter-jurisdictional Allocation Protocol ("2020 Protocol") approved by the Commission.[2]

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Utah Large Customer Group ("UTLCG") in this proceeding. UTLCG members operate commercial and industrial facilities within RMP's service territory and purchase electricity and energy services from RMP. Members of the UTLCG receive electric service through RMP Electric Service Schedule No. 9, General Service – High Voltage, which is supplied at approximately 46 kV or 69 kV or greater.

Q. HAVE YOU PROVIDED EXPERT TESTIMONY IN REGULATORY PROCEEDINGS BEFORE?

A. Yes. I have provided testimony in proceedings in Utah, Idaho, Wyoming, Oregon, Washington, California, and Nevada.

[2] *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___(JRS-1) (hereinafter the "2020 Protocol"); *see also id.* at Order Approving 2020 Protocol (Apr. 15, 2020).

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to (1) provide UTLCG's overall response to PacifiCorp's proposed 2026 PacifiCorp Inter-Jurisdictional Allocation Protocol ("2026 Protocol"), (2) introduce the witness team supporting UTLCG's response, and (3) provide an alternative framework for an allocation method in lieu of PacifiCorp's proposal that better balances the Company's interest in cost recovery with Utah's interests in just and reasonable rates.

My silence with respect to any position taken by RMP in its application or testimony in this proceeding should not be interpreted as an endorsement of that position.

Q. WHO WILL ASSIST YOU IN PRESENTING THE UTLCG'S RESPONSE TO THE COMPANY'S 2026 PROTOCOL?

A. UTLCG witness Bradley G. Mullins provides additional details supporting UTLCG's concerns with the 2026 Protocol, as well as support for the alternative framework that I will outline in this testimony.

Q. WHAT IS YOUR SPECIFIC RECOMMENDATION IN THIS CASE?

A. Given the proposal's foundational flaws, I recommend that the Commission reject PacifiCorp's 2026 Protocol and consider the alternative paths I present below.

Fundamentally, the 2026 Protocol is ill-conceived and flawed because it satisfies Washington policy goals at the expense of Utah customers and boosts the Company's earnings while leaving many issues unanswered and unresolved. Specifically, the proposal would allocate an additional $49.3 million[3] to the five states of Utah, Idaho, Wyoming,

[3] Direct Testimony of Shelley E. McCoy, p. 2, line 31, Table 1. These amounts are questionable and addressed later in this testimony.

Oregon, and California[4] (the "Five States") while reducing costs to Washington.[5] The Company's proposal shifts costs to the Five States without providing any plant-by-plant cost benefit analysis of the proposed asset swaps or reassignments.

For example, the 2026 Protocol proposal calls for the Five States to "trade" the Chehalis Plant and its costs and benefits to Washington. In exchange, the Five States receive an increased allocation of the costs and benefits of *unallocated* coal and east-side gas plants (*i.e.*, plants that the Five States treat as already allocated to Washington, but which have not been included in Washington rates since at least 2008). The fact that Washington has not included its share of these unallocated plants in its rates provided the opportunity for the Company to recommend a thoughtful reassignment of what would otherwise be Washington's share of these plants. But the Company opted not to pursue that, and parties lack the ability to meaningfully develop that comparison absent the Company's analytical support.

The proposed 2026 Protocol does not follow the 2020 Protocol's reassignment process and instead exacerbated the issues caused by Washington's decadeslong use of a different jurisdictional allocation methodology. The historic problem—which is exacerbated in the 2026 Protocol—is PacifiCorp's placing primacy on serving Washington's energy and capacity needs from Washington's preferred selection of the

[4] California has been a passive participant to multi-state allocation discussions but has not actively negotiated or signed agreements. The methodology used in Utah, Idaho, Wyoming, and Oregon has typically been approved in California through general rate cases over time.

[5] *See Washington Utilities and Transportation Commission v. PacifiCorp dba Pacific Power and Light Co.*, Docket No. UE-250224 (hereinafter "2026 Washington Protocol Docket"), Final Order Rejecting Tariff Sheets; Granting Petition in Part, Subject to Conditions; Authorizing and Requiring Compliance Filing, p. 88, ¶ 306 (Dec. 22, 2025) (hereinafter "2026 Washington Protocol Order"): "The record evidence supports the 2026 Protocol is a substantial improvement over the WIJAM, and that use of the WIJAM would have increased NPC by $80 million in this case, with continuation of the WIJAM resulting in a rate increase of $80 million as compared to a $12 million increase under the 2026 Protocol."

Company's suite of generation assets, while the Five States pay for it.

Furthermore, the 2026 Protocol is shortsighted and only "solves" the Washington issue, leaving looming and unresolved larger issues, such as Oregon's upcoming exit from emitting thermal resources, to what the Company calls "Phase 2":

> 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.[6]

The contemplated Phase 2 of the 2026 Protocol may be perceived as a light at the end of the tunnel with a path to resolution, but it is not. If these issues are not resolved now or, at least, very soon, the situation can be better likened to a freight train that is barreling down on PacifiCorp, its customers, and its regulators. Again, the proposal invites more questions than answers.

Q. WHY IS WASHINGTON THE COMPANY'S FOCUS IN THE PROPOSED 2026 PROTOCOL?

A. Stakeholders in the Five States and the Company have worked together to negotiate in good faith to implement several allocation agreements over many years that provided the Company with the means to recover costs on a system basis. In contrast, the Company has developed and implemented separate allocation agreements with the parties in Washington, leading to allocation shortfalls compared to a system approach. This case is tantamount to the tail (Washington at about 7.5% of the system) wagging the dog (Five States at about 92.5% of the system). The Company's approach may address policy issues and cost

[6] Direct Testimony of Rick T. Link, p. 16, lines 311-316.

recovery in Washington, but it leaves the Five States to pick up a perceived shortfall. Rather than addressing reassignment of generation and a potential swap of Chehalis with the vast majority of the system (the Five States) and then turning to Washington, the Company first addressed the Washington situation[7] and the associated fact that the commissions in Idaho, Oregon, Utah, and Wyoming have disallowed Washington Climate Commitment Act greenhouse gas allowance costs ("CCA Costs") ($54.9 million[8] total-Company in 2026). Boiled down, the Company proposes an unjust and unreasonable trade: Washington would receive all of the costs and benefits for Chehalis—a valuable facility historically funded by and serving the Five States—in exchange for the Five States assuming responsibility for additional coal and east-side gas generation assets that have provided and continue to provide benefits to Washington at no cost. It is not surprising that this lopsided and dubious deal increases costs for the Five States and decreases Washington costs.

Q. IF THE COMMISSION REJECTS THE 2026 PROTOCOL, WHAT OPTIONS ARE LEFT FOR THE COMMISSION SINCE THE 2020 PROTOCOL EXPIRED DECEMBER 31, 2025?

A. The Commission is not required to resolve jurisdictional cost allocation issues outside of rate proceedings where the allocations are used to set rates. The Commission is also not obligated to approve the same allocation methodology used in other states. Given the flaws with the 2026 Protocol, the public interest in Utah would be best served by:

1. Rejecting the 2026 Protocol.

[7] By assigning Chehalis Gas Plant 100% to Washington, the Company may receive free allowances from Washington regulators. *See* Response to UTLCG Data Request 1.8, subparts a and b (provided in Exhibit JKL-5).
[8] Direct Testimony of Rick T. Link, p. 22, lines 424-425.

2. Until a new cost allocation methodology is approved, ordering the Company to submit rate filings using the 2020 Protocol methodology. The 2020 Protocol was used in the last general rate case and is the basis for current rates. Presenting costs and benefits using the 2020 Protocol will provide a consistent and known basis upon which all parties and the Commission can evaluate the rate filings and any alternative interstate cost allocation proposals. Until a new cost allocation methodology is approved, the Company and the parties may also recommend revisiting interstate cost allocation in rate proceedings. However, doing so requires significant data from the Company and can significantly increase a case's complexity. If the Company were to file a rate case and only present the case with information based on a proposed new interstate cost allocation methodology without including the information regarding the allocation under the 2020 Protocol, it would be next to impossible for parties and the Commission to unpack that proposal in the timeframe the Commission has to decide the case.

3. Staying this case or opening an investigatory docket and ordering the Company to participate in joint discussions with parties in the state, and, to the extent possible, collaborate with stakeholders for the other Five States, and provide needed analytics to present to the Commission a solution with a defined deadline for a report (*e.g.*, August 31, 2026). This will allow parties to continue to propound discovery to develop and refine proposals. The Allocation Framework I am recommending (attached as Exhibit JKL-1 to this testimony) could be the basis for guiding these discussions.

4. Alternatively, the Commission could reject the 2026 Protocol and order a new

allocation method in this case if the Commission finds sufficient evidence supporting cost causation of the allocation of generation, transmission, system overheads, taxes, and other allocable costs. The Allocation Framework in Exhibit JKL-1 could be the basis for an alternative approach.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is structured with the following main sections:

- Background and History of Cost Allocations
- Utah Cost Recovery
- Washington Issues
- 2026 Protocol / Washington 2026 Protocol
- Other 2026 Protocol Issues
- Allocation Framework
- Recommendation
- Summary and Conclusion

III. BACKGROUND AND HISTORY OF PACIFICORP'S COST ALLOCATIONS

Q. PLEASE PROVIDE AN OVERVIEW ON THE COMPANY'S REVENUE REQUIREMENT INTERSTATE ALLOCATIONS.

A. Notably, not all of the costs in the Company's revenue requirement are allocated on an interstate basis. About 30% of the costs in the Company's revenue requirement are distribution-related costs that have always been viewed as state-specific costs that are driven by customer requirements within a state. Those state-specific distribution costs are "situs" assigned to each state rather than being allocated.

The other 70% of the Company's revenue requirement is subject to interstate

allocation and can be generally thought of in three categories: (1) generation, (2) transmission, and (3) administrative and general, taxes, and other. For these buckets, the process for determining the method of assignment is to first analyze the costs incurred and determine what function they support within these three categories. Then the costs need to be classified in terms of what the underlying drivers are for the incurrence of the costs. For example, costs may be the result of customer service and driven by the number of customers on the system, or costs may be fuel-related and, therefore, directly tied to the number of megawatt-hours produced from the fuel. Once costs are functionalized, they are then classified into categories related to the drivers of the costs if they can be identified, such as demand-related, energy-related, customer-related, or undefinable overheads. With the functionalization and classification completed, specific allocation factors can be created to assign or apportion the costs to states or customer classes within the states.

Q. PLEASE PROVIDE A SHORT SUMMARY OF THE HISTORY OF COST ALLOCATIONS USED BY PACIFICORP AND ITS PREDECESSOR COMPANIES.

A. The allocation of generation and transmission assets used to serve a single system has been a continuing topic of discussion and negotiations among states, even before the merger between Pacific Power and Utah Power. In the legacy Utah Power system, Utah, Idaho, and western Wyoming[9] used an allocation system for generation and transmission primarily based on factors derived from eight coincident monthly peaks ("CP") during an annual period with no weighting for energy. The Pacific Power states (Oregon,

[9] At the time of the merger, Utah Power served western Wyoming and Pacific Power served eastern Wyoming. Separate service territories and tariffs were maintained over a period of time in Wyoming until they were merged and tariffs were consolidated.

Washington, Montana,[10] and California) used 60 CPs (average of five years of monthly coincident peaks) and 24 months of energy, weighted on a 50% demand and 50% energy basis. Post-merger, the allocation of system-related generation and transmission costs relied on 12 CPs and 12 months of energy, weighted 75% demand-related and 25% energy-related.

Q. WERE PRE-MERGER AND POST-MERGER SYSTEM PLANT INVESTMENTS TREATED DIFFERENTLY?

A. Yes. The merger of the two companies brought together UP&L's system, which was primarily thermal (coal) based and higher-cost, and PP&L's system, which was more hydro-based and lower-cost. As a result, starting in 1989, assets were divided into pre- and post-merger investment classifications, along with all associated costs, such as depreciation. This approach prevented the merger from causing pressure for immediate rate increases in PP&L states and rate decreases in UP&L states at the outset of the merger. As post-merger investments were made to support system growth and capital maintenance was undertaken, the costs were categorized as system investment and allocated on a system basis. As pre-merger plant balances were depreciated and decreased over time, the post-merger investments grew and the disparity decreased. This put interjurisdictional allocation on a path toward what's commonly referred to as a "rolled-in," system-wide approach.

[10] The Montana service territory was subsequently sold and is no longer a part of the allocation process.

Q. WERE VARIOUS ALLOCATION METHODOLOGIES USED OVER TIME TO MANAGE THE CONSOLIDATION OF THE TWO COMPANIES AND MANAGE COST DISPARITIES AMONGST THE STATES?

A. Yes. Various methods such as the Bold Course, Consensus, Accord, Modified Accord, Revised Protocol, 2010 Protocol, 2017 Protocol, and 2020 Protocol were used. There have also been Washington specific methodologies used such as the West Control Area method ("WCA") and the Washington Inter-jurisdictional Allocation Methodology ("WIJAM"). The methods employed various concepts such as the pre- and post-merger system cost allocations, hydro and wheeling endowments, merger fairness adjustments or embedded cost differential ("ECD") adjustments, and other negotiated trade-offs to address cost causation principles, fairness, and merger consolidation over time.

IV. UTAH COST RECOVERY

Q. HAS THE USE OF VARIOUS COST ALLOCATION METHODS OVER THE YEARS IN UTAH AFFECTED THE COMPANY'S ABILITY TO EARN ITS AUTHORIZED RETURN?

A. Not in Utah. For decades, Utah has participated in the multi-state process, joining the multi-state allocation agreements and making concessions from litigation positions to reach compromises and settlements with the other states, and supporting an allocation methodology that would provide PacifiCorp an opportunity for full cost recovery if it was used by all states. Where there have been specific cost disallowances in Utah under the different allocation methodologies, that does not suggest a failure of the allocation method, but rather a feature of utility regulation that protects customers against Company decisions that may be imprudent or otherwise not beneficial to customers in each state. Furthermore,

as an express condition of approving the merger, the Commission required that PacifiCorp assume the risk of any cost recovery shortfalls that arise because of conflicting cost allocation methodologies between the states. The order states:

> The Merged Company shall agree that PacifiCorp shareholders shall assume all risks that may result from less than full system cost recovery if inter-jurisdictional allocation methods differ among the Merged Company's various jurisdictions.[11]

Q. ARE THE COST ALLOCATION METHODS IN THE 2020 PROTOCOL CURRENTLY IN PLACE IN UTAH CREATING AN ISSUE FOR THE COMPANY?

A. Potentially, but, again, not in Utah. Company witness Cindy A. Crane raises concerns in this proceeding about the Company's ability to fully recover its costs to support its financial health.[12] However, she conflates the Company's recovery of allocable costs with PacifiCorp's cost recovery related to fire liabilities or state policies. Indeed, any disallowances were primarily due to Company actions that were not approved by the states within the framework of an approved allocation methodology.[13]

Q. WITH RESPECT TO YOUR DISCUSSION OF THE MULTI-STATE NEGOTIATIONS AND METHODOLOGIES, DID ALL STATES PARTICIPATE?

A. Yes, generally. Washington has historically participated in multi-state negotiations but

[11] *In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp.*, Docket No. 87-035-27, Report and Order, p. 97, ¶ 11 (Sept. 28, 1988).

[12] Direct Testimony of Cindy A. Crane, pp. 4-5, lines 84-102.

[13] *Applications of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah, Approval of its Proposed Electric Service Schedules and Electric Service Regulations, and for a Deferred Accounting Order Regarding Insurance Costs, and 2023 Wildland Fire Protection Plan*, combined Docket Nos. 24-035-04, 23-035-40, and 23-035-44, Order, p. iii (April 25, 2025): "Fifth, the PSC's order also reflects our view that incremental costs incurred by PacifiCorp due to specific state climate action policies or specific state agreements driven by individual state circumstances (particularly in Washington and Oregon) should not be borne by Utah ratepayers. We thus remove from Utah rates $13 million in costs directly associated with Washington's climate policies which were not equally assigned to that state's own customers."

always approved its own unique approach. I will address the challenges with Washington in the next section. California has intermittently engaged in the multi-state negotiation process over the years.

V. WASHINGTON ISSUES

A. Allocation Shortfall / Surplus

Q. HAS THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION ("WUTC") EVER APPROVED AN INTERJURISDICTIONAL COST ALLOCATION METHOD AGREED TO BY THE OTHER FIVE STATES?

A. No. Historically, Washington parties have participated in various multi-state allocation discussions, but the Washington parties did not advance, nor has the WUTC ever approved, an agreement reached with the other states.[14] Just recently, the WUTC conditionally approved the use of the 2026 Protocol[15] but, of course, that approach was crafted specifically to address Washington's needs and has not been approved in any other PacifiCorp state as of the time this testimony was filed.

Q. WHAT HAS BEEN PACIFICORP'S HISTORIC POSITION ON A MULTI-STATE ALLOCATION METHOD IN WASHINGTON?

A. Historically, PacifiCorp sought to have a single allocation methodology used in all six states. For example, in a 2006 WUTC rate case order, the WUTC stated

> PacifiCorp commits in the Revised Protocol to plan and operate its generation and transmission system on an integrated systemwide basis to "achieve a least cost/least risk Resource portfolio for its customers." If all the states follow the Revised Protocol, PacifiCorp asserts it will have a reasonable opportunity to recover all of its prudently incurred expenses and investments and earn its

[14] *Washington Utilities and Transportation Commission v. PacifiCorp* and *In the Matter of the Petition of PacifiCorp for an Order Approving Deferral of Costs Related to Declining Hydro Generation*, Docket UE-050684, Order 04 and Docket UE-050412, Order 03, p. 12, ¶ 28 (April 17, 2006) (hereinafter "WUTC Hydro Deferral Docket Order") (internal citation omitted).

[15] *See* 2026 Washington Protocol Order, pp. 97-99, ¶¶ 385-401.

authorized rate of return.[16]

The Company's position has been, generally, that if all states follow a system allocation approach, then PacifiCorp will have a reasonable opportunity to recover all of its prudently incurred costs.

Q. WHY IS PACIFICORP'S POSITION ON THIS IMPORTANT?

A. If PacifiCorp believed it had a reasonable opportunity to recover all of its prudently incurred costs and earn a return on its investment when all six states in its service territory followed a single allocation protocol, one state's decision to deviate from the rest should not burden the other Five States. Instead, that risk has always been and should always be borne by the Company.

Q. WHEN THE WUTC REJECTED THE REVISED PROTOCOL IN 2006, DID THE COMPANY WORK TO DEVELOP A SEPARATE METHOD FOR WASHINGTON?

A. Yes. In 2006, the Company worked with the WUTC Staff and developed the WCA methodology in 2007 and later developed the WIJAM.[17] The WIJAM continued in parallel with the 2020 Protocol agreement until 2025. As compared to the system allocation of costs by the Five States, both the WCA and the WIJAM were based on a methodology that primarily treated generation on a divisional basis due to the WUTC's finding that "there are significant transmission constraints impeding the exchange of power between the Western and Eastern control area."[18] Other issues also played into the WUTC's decision, such as increasing load growth and asset acquisitions to meet such load in other states. The

[16] WUTC Hydro Deferral Docket Order, p. 12, ¶ 28 (internal citation omitted).
[17] Response to UTLCG Data Request 2.16 (provided in Exhibit JKL-5).
[18] WUTC Hydro Deferral Docket Order, p. 22, ¶ 53 (internal citation omitted).

Company supported a path that led to alternative allocation methods and resulting risks, with full understanding that having a different allocation approach in Washington could lead to the Company having costs that are either over- or under-allocated between the six states. That, in turn, could lead to costs being over or under-recovered, impacting the Company's ability to earn its authorized returns.

Q. PLEASE PROVIDE ADDITIONAL DETAILS ON WASHINGTON'S APPROACH.

A. Washington's approach primarily relied on the divisional allocation (*i.e.,* east-side/west-side) of generation and transmission costs under the WCA, and thermal generation under the WIJAM. Based on those assumptions, Washington accepted an allocation based on its load share of the three west coast states (Oregon, Washington, and California). Currently, that load share results in Washington being allocated approximately 21% of generation and transmission[19] located in the Pacific Power service territory or what is sometimes called the west side of the system. However, under a six-state system-allocation approach, Washington should be allocated approximately 7.5% of all system generation and transmission. As a result, the WIJAM allocation approach resulted in an overallocation of approximately 13%[20] of Bridger, Colstrip, Chehalis, and Hermiston. Conversely, Washington did not view the thermal resources in the legacy Utah Power territory, what is sometimes called the east side of the system, as serving the state and, therefore, did not include costs for those resources in rates in Washington. This resulted in only 92.5% on the remainder of the Company's thermal generation fleet being allocated to the non-Washington states.

[19] The WIJAM method transitioned the transmission cost allocations from divisional to system over a 3-year period beginning in 2021. *See* 2020 Protocol, Appendix F, WIJAM Memorandum of Understanding, pp. 3-4, Section 4.1 (Dec. 3, 2019).

[20] 100% - 7.5% = 92.5% from Five States. 92.5% + 21% from Washington = 112.5%.

Q. DID THE OVERALLOCATION OF WEST-SIDE ASSETS FILL THE ALLOCATION HOLE IN PRACTICE?

A. Yes, to some extent. The divisional approach may have mitigated the issue, but it did not eliminate it, and over time the allocation shortfall or surplus has persisted.

Q. HAS ANY ALLOCATION SHORTFALL BEEN DOCUMENTED IN THE COMPANY'S STATE-BY-STATE EARNINGS FILINGS OVER THE YEARS?

A. No. In my experience, the Company would prepare semi-annual Results of Operations ("ROO") reports based on unadjusted total Company information. First, the unadjusted results would be allocated on a system-wide basis using the prevailing multi-state allocation agreement. Unadjusted results do not include state specific ratemaking adjustments or proforma adjustments that differ state by state. It is a function of cost allocations across all states and should result in 100% cost allocations. Second, each state's unadjusted results would be adjusted for the proper ratemaking treatment and adjustments allowed or ordered in their state. This results in the ROO Reports filed semi-annually or annually in many states, or the basis for general rate cases. The reports reflect the unadjusted and adjusted costs in each state's report.

But for Washington, the system allocated costs would be replaced with the WCA or WIJAM costs, without any comparison to the system approach used by the Five States. As a result, the sum of the unadjusted ROO Reports provided to the six state jurisdictions should be viewed critically as that sum will likely not reflect the actual ROOs for the Company.

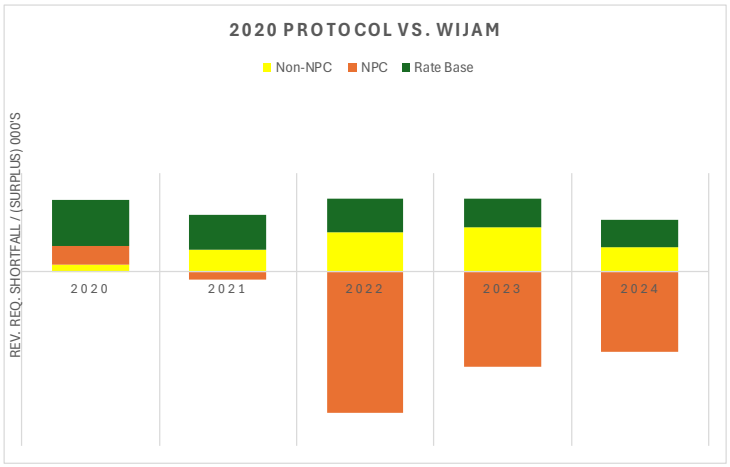
Q. HAVE YOU PREPARED A TABLE TO DEMONSTRATE THIS PROBLEM?

A. Yes. Table JKL-1 is a comparison of the Company's Washington unadjusted results of

operations from 2020 to 2024, comparing the allocation of the costs as allocated under the 2020 Protocol (Five States), and the WIJAM cost allocation. Positive amounts represent the shortfall in cost allocations and negative amounts are a surplus or windfall (*i.e.*, overallocation of costs).

Table JKL-1[21]

2020 Protocol vs. WIJAM



	2020	2021	2022	2023	2024
Non-NPC	2,767	8,802	15,806	17,953	10,012
NPC	7,973	(2,920)	(56,694)	(38,387)	(32,253)
Rate Base	18,140	14,441	13,722	11,777	11,040
Total	30,900	22,345	(25,144)	(6,634)	(9,177)
Net Power Cost Detail					
Sales for Resale - NPC in 447	5,792,264	13,649,321	19,137,495	11,032,412	6,996,704
Fuel - NPC in 501	4,839,840	3,888,978	4,691,292	(220,130)	21,836,027
Fuel - Steam Other in 503	0	0	1,142,370	209,869	157,897
Fuel - NPC in 547	456,470	(2,257,862)	(7,817,690)	1,018,849	(19,734,314)
Purchased Power - NPC in 555	23,258,244	(18,053,175)	(35,307,754)	(28,224,773)	(27,313,912)
Wheeling - NPC in 565	(14,789,191)	(146,878)	(264,340)	(138,776)	(202,484)
Total Net Power Cost Estimate	7,973,099	(2,919,616)	(56,693,617)	(38,387,373)	(32,253,490)

Source: 2020 through 2024 Results of Operations Reports, WY ROO UTCR Tab, 13-month Avg using the 2020 Protocol. WA WIJAM results from the WA ROO UTCR tab with avg. of monthly averages. Response to Data Request UTLCG 2.3

[21] Source for Five State Data: Response to UTLCG Data Request 2.3, Attachment UTLCG 2.3, Workpapers 2020 – 2024 Results of Operations.xlsx, Tabs WY ROO UTCR (applying the 2020 Protocol to 13-month average). Source for Washington Data: *Id.* at Workpapers 2020 – 2024 Results of Operations.xlsx, Tabs WA ROO UTCR (applying the WIJAM to average of monthly averages).

Q. PLEASE EXPLAIN TABLE JKL-1.

A. Company data allows for a comparison of total system costs using different allocators. In this analysis based on Company ROO Reports data, I prepared a Washington estimate of the cost allocation under the 2020 Protocol provided by the Company and compared it to the WIJAM allocation of costs in the Washington ROO Reports and calculated the difference. I broke the results into the three categories of costs for (1) rate base, (2) non-net power costs ("NPC"), and (3) NPC costs for the years 2020 - 2024.

Q. DID YOU ASK THE COMPANY TO PERFORM A SIMILAR CALCULATION?

A. Yes, but the Company refused to complete a comparison of Washington using the 2020 Protocol used by the Five States. This made evaluating the reasonableness of the Company's proposal very difficult.

B. Rate Base

Q. PLEASE EXPLAIN THE ALLOCATION DIFFERENTIAL FOR RATE BASE IN TABLE JKL-1.

A. The size of the rate base delta ranged from $124 million to $205 million over the referenced years. I converted this investment into an estimated revenue requirement amount, resulting in the range of $11.0 to $18.1 million in estimated revenue requirement shortfall. This differential is fairly consistent over the period. Related to this rate base investment but included in the net power costs are the coal and gas costs that would be over- or under-allocated based on the divisional or system allocation of generation plant. For example, Washington NPC would include approximately 21% of Bridger coal costs but zero Hunter coal costs. The treatment of depreciation would follow the same pattern. These costs are in the non-NPC and NPC categories.

Q. WHAT INFLUENCES THE CHANGES TO THE RATE BASE RESULTS?

A. Because the WCA and WIJAM methods were based on divisional generation investment and because thermal investment in the east side of the PacifiCorp system grew faster than thermal investment in the west, the allocation shortfall has generally grown over the years; however, it would also be impacted by retirements. Coal plant closures caused even more volatility in this differential. Looking forward, the Washington exit from Bridger 3 and 4 starting in 2026 will also significantly impact this differential unless Washington pays off its share on exit.

Q. CAN YOU PROVIDE AN ESTIMATE OF THE GENERATION (IN MWs) AFFECTED BY WASHINGTON EXCLUDING COAL AND EAST-SIDE GAS AND THE UPCOMING OREGON COAL EXIT?

A. Yes. Table JKL-2 below presents information from the 2024 FERC Form 1[22] on the "Net Continuous Plant Capability" and Washington's and Oregon's system allocated share. For Oregon, the 2024 allocation percentage is used as a proxy for the 2029 impact. Table JKL-2 reflects an approximate 522 MWs of under-allocated generation due to Washington, and 883 MWs of under-allocated generation due to Oregon starting in 2030.

[22] 2024 PacifiCorp FERC Form 1, pp. 402-403, line no. 8, available online here: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250415-8037 (last accessed Feb. 1, 2026).

Table JKL-2[23]

Potential Generation Plant MWs Excluded from Washington (and Oregon in 2030)

	Potential Generation Plant MWs Excluded from Washington (and Oregon in 2030)				
		Total MWs - Net Continuous Plant Capability	Washington - 7.5%	Oregon - 26.2% (2024 proxy for 2029)	Comments
	East-Side Gas:				
1	Current Creek	550	41		Gas
2	Lakeside	1,203	90		Gas
3	Naughton Gas	647	49		Gas Conversion
4	Gadsby Peakers	120	9		Gas - 2032 Planned exit
5	Gadsby Steam	238	18		Gas - 2032 planned exit
6	Dave Johnston 1, 2, 4	205	15		Gas - Conversion of Units 1&2; 2039 unit 4 exit
	West-Side Gas:				
7	Hermiston	237	18		Gas
	All Coal:				
6	Dave Johnston 4	330	25	86	Coal - 2039 unit 4 exit
8	Wyodak	268	20	70	Coal
9	Bridger 3&4	706	53	185	Coal
10	Hunter	1,158	87	303	Coal
11	Huntington	909	68	238	Coal
12	Colstrip 4	148	11		Coal - 2029 planned exit
13	Craig	161	12		Coal - 2028 planned exit - not available for long-term subscription
14	Hayden	77	6		Coal - 2027-28 planned exit - not available for long-term subscription
15	Total	6,957	522	883	
16	Chehalis - System 7.5%	518	39		Gas
17	Chehalis - WIJAM 21.6%	518	112		Gas
18	Chehalis - 2026 WA Proto 100%	518	518		Gas

C. Non-Net Power Costs

For the remaining costs shown in Table JKL-1 excluding rate base, I separated out the NPC from the total "operating revenue for return" total by identifying the NPC line-item details and backing them out of this total. Retail revenues remain constant between methods and the only element that changed is system vs. divisional allocations. The non-NPC costs reflect any differences in costs such as depreciation, operating and maintenance expense on plants, overheads, etc. The result has been a consistent shortfall, but the amount of the

[23] Sources: *Id.*; and allocations from Response to UTLCG Data Request 2.3, Attachment UTLCG 2.3, Workpaper 2024 Results of Operations.xlsx.

shortfall has varied over the years.

Q. IS IT POSSIBLE THAT YOUR ANALYSIS IN TABLE JKL-1 UNDERSTATES THE ALLOCATION SHORTFALL ASSOCIATED WITH THE RATE BASE AND NON-NPC CATEGORIES?

A. Yes. While the workpaper supplied by Company witness Shelley E. McCoy compared allocations under the 2020 Protocol to the 2026 Protocol, I compared the allocation of the generation plant costs under the 2020 Protocol to the allocation under the WIJAM for 2024. The Company's analysis provides all of the non-NPC costs for each plant on a revenue requirement basis. This means the Company's analysis includes the return on investment, operating expenses, depreciation, deferred taxes, etc., but excludes the NPC results. Using this alternative approach for 2024 alone, the results shown in Table JKL-3 below reflect a shortfall before NPC of $22.7 million as compared to the shortfall in Table JKL-1 of $21.0 million ($10.0 million non-NPC + $11.0 million rate base).

Table JKL-3[24]
Total Non-NPC Revenue Requirement

	Total Non-NPC Revenue Requirement		
	2020 Protocol	WA WIJAM / 5 States Protocol	Difference
SG 5A - JB 1 2 and Renewables	$ 49,968,346	$ 66,994,693	$ (17,026,347)
SG 5b - Thermal	$ 72,664,066	$ 32,888,711	$ 39,775,355
SG5C - Rolling Hills	1,516,147	1,515,824	$ 323
Total	$ 124,148,559	$ 101,399,228	$ 22,749,331

Original Data In McCoy worksheet realocated on WIJAM factors for Washington and compared to the 2020 Protocol data for Washington in the worksheet

[24] Source: Direct Testimony of Shelley E. McCoy, Workpaper 340936RMPAtt2SEMWrkprs8-5-25.xlsx, modified to calculate the difference in methods.

D. Net Power Costs

Q. WHAT CONCERNS DO YOU HAVE WITH THE COMPANY'S PRESENTATION OF NPC DATA FROM YEARS 2021-2024?

A. As I prepared and analyzed the Company's data, I came across significant disparities in NPC from 2021 to 2024. This is based on what I interpret to be a new Company practice of removing the allocation of Washington costs on the WIJAM basis in unadjusted results and replacing the allocations with a single "plugged amount" in each category of NPC.[25] For example, Table JKL-4 is a screenshot from the Company's 2024 ROO Report for Washington for FERC account 555, Purchased Power-NPC. Table JKL-4 shows that rather than an allocation of total Company amounts under WIJAM allocators (CAGW, CAEW, etc.), a situs amount of $140.3 million for Washington is inserted into both the Total Company column and the Washington column, rendering the Total column worthless. Prior to 2022, the allocation of costs were properly reflected and auditable in the NPC accounts. The result is that the total of the Five States' NPC and Washington's NPC does not add to the actual total Company NPC. This practice has led to total NPC costs being substantially overstated from 2022 to 2024 as compared to actual costs. I will note that UTLCG witness Mullins's analysis of this same issue for 2024 used a different methodology and reached a similar conclusion, but his analysis suggests that the overstatement may be even larger than I estimated.

[25] These categories include Sales for Resale (447), Fuel (501, 503, 547), Purchased Power (555), and Wheeling (565).

Table JKL-4[26]

WIJAM Total Company Plug – FERC Account 555

	DECEMBER 2024 Washington Inter-Jurisdictional Allocation Methodology									
	AVERAGE-OF-MONTHLY-AVERAGES									
	FERC			WIJAM		UNADJUSTED RESULTS			WASHINGTON	
	ACCT	DESCRIP		FACTOR	Ref	TOTAL	OTHER	WASHINGTON	ADJUSTMENT	ADJ TOTAL
581	555NPC	Purchased Power-NPC								
582				SG		-	-	-	-	-
583				SE		-	-	-	-	-
584				CAGW		-	-	-	-	-
585				CAGW		-	-	-	-	-
586				CAGE		-	-	-	-	-
587				CAEW		-	-	-	-	-
588				CAEE		-	-	-	-	-
589				DGP		-	-	-	-	-
590				S		140,258,617	-	140,258,617	(8,851,381)	131,407,237
591						140,258,617	-	140,258,617	(8,851,381)	131,407,237

Q. WHAT WOULD YOU INFER FROM THE OVERALLOCATION OR ASSIGNMENT OF COSTS IN THE 2022-2024 TIMEFRAME?

A. If the data is correct, the Company has been over-allocating or assigning NPC to Washington during this period. While Washington, like all of the states, is physically served by a single portfolio of assets, the Company has furthered a fictional pricing scheme to remove coal from rates to comply with Washington State energy policy. Additionally, if these skewed costs became the basis for ratemaking, this would explain why the WUTC understood that moving from the WIJAM to the 2026 Protocol would be substantially less expensive for Washington consumers.[27]

Q. HAVE YOU REVIEWED THE DIFFERENCE BETWEEN THE 2020 PROTOCOL AT A TOTAL COMPANY LEVEL COMPARED TO THE SAME RESULTS WITH WASHINGTON'S USE OF WIJAM?

A. Yes, Exhibit JKL-2 is a comparison of 2024 Total Company Unadjusted ROO based on the 2020 Protocol for all states compared to the same information but replacing the Washington results column with WIJAM results from the 2024 Washington ROO Report.

[26] Response to UTLCG Data Request 2.3 (provided in Exhibit JKL-5), Attachment UTLCG 2.3, Workpaper 2024 Results of Operations.xlsx, Tab WA ROO Report, Cells A:709-M:719.
[27] *See* 2026 Washington Protocol Order, p. 88, ¶ 306 (full quotation provided *supra* note 5).

The comparison in Exhibit JKL-2 gives a total Company view of the cost structure of the Company and the comparison between allocation methods. The difference reflects the similar results to Table JKL-1, namely that operating costs are over-allocated (mainly NPC), reducing the "Operating Revenue for Return" while plant investment is under-allocated, summing to an $11 million surplus.

Q. DOES THIS MEAN THAT THE COMPANY MAY BE OVER-EARNING BECAUSE OF DIFFERENT ALLOCATION METHODS?

A. Not necessarily. The analysis above is purely a function of cost allocations and does not reflect rates that are ultimately set by each commission. However, the unadjusted results are the basis for the starting process to set rates. If the Company over-allocates NPC costs or otherwise includes costs in Washington that reflect a theoretical cost structure based on generation and purchased power assumptions that exclude coal and gas to satisfy that state's policy directives, they may over-collect the actual costs that the Company has incurred even though they under-allocated the rate base and related costs. Regardless, one must take the Company's assertions of an ongoing allocation shortfall with a grain of salt and question whether there is a need to address a shortfall by altering the cost allocation regime.

Q. HAS THE COMPANY PERFORMED ANY ANALYSIS OF AN ALLOCATION SHORTFALL SINCE AT LEAST 2020 TO DETERMINE WHETHER THEY HAVE AN ALLOCATION PROBLEM?

A. No. The Company responded to discovery stating:

> For calendar years 2020 through 2024, the Company has not performed or maintained analysis to calculate what the total Company earnings shortfall by year would have been for the Washington Western Control Area Allocation Methodology (WCA) and Washington Inter-Jurisdictional Allocation

> Methodology (WIJAM) used in Washington as a result of not having a common six-state allocation method. Such analysis would require Washington's earnings to be assessed both on WCA/WIJAM and the 2020 Inter-Jurisdictional Cost Allocation Methodology (2020 Protocol) in order to have a relative comparison, and the Company has never calculated Washington's result of operations (ROO) under the 2020 Protocol since it is not an approved allocation methodology for the purposes of ratemaking in Washington.[28]

Q. DOES THIS RESPONSE CONCERN YOU?

A. Yes. First, I don't understand how PacifiCorp can assert that it has an allocation problem in this case if the Company doesn't undertake an analysis of the six states, in a manner similar to what I have prepared. Second, the analysis is not a comparison of Washington's "earnings," but of cost allocation methodologies. Put differently, the goal is not to assess Washington allocations under the 2020 Protocol for purposes of "ratemaking in Washington," but rather to understand, and substantiate, alleged cost allocation shortfalls. Finally, the Company supplied ROO Excel files[29] for each year from 2020 to 2024. Each year includes ROO tabs for all states except California with a "UTCR" tab that includes a six-state allocation under the 2020 Protocol, excepting Washington. The Washington results are based separately on the WIJAM ROO. Because the comparison of 2020 Protocol to WIJAM is not difficult, this would not seem to be a heavy lift for the Company to prepare.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH COMPANY DATA?

A. Yes. In my analysis, I attempted to start with total Company data to make sure that the states summed up to the total to evaluate any alleged allocation hole. However, I found that all the total Company columns in each ROO Report were different each year from

[28] Response to UTLCG Data Request 7.2, subpart a (provided in Exhibit JKL-5).
[29] *See* Response to UTLCG Data Request 2.3 (provided in Exhibit JKL-5).

2021 to 2024. Exhibit JKL-3 is a comparison of the total Company column on the UTCR Tab from each state's Results of Operations Reports from 2021 to 2024. I cut and pasted the total from each state for each year into a single file to do a side-by-side comparison. Some FERC accounts and categories matched and others were different. I compared the ROO reports to a sampling of category totals in the FERC Form 1 reports for the four years and found additional differences. While the development of the jurisdictional results used for ratemaking typically require some degree of adjustment or correction, these should be transparent and identified so that audit trails can be maintained, and regulators can have confidence in the data. In my opinion and based on the information provided by the Company, the Company's concerns regarding under-recovery, which concerns drive both the Company's proposed new cost allocation methodology and requested deferral, are speculative at best.

Q. HOW DO YOU RECOMMEND RESOLVING THIS ISSUE SO THAT ALLOCATIONS ARE TRANSPARENT AND AUDITABLE TO COMPANY RECORDS?

A. I recommend that: (1) the Company's results of operations reports tie to the FERC Form 1 as a starting point; (2) accounting corrections, reclassifications, or factor changes within an account be explicitly identified; (3) revenues or costs assigned to "Other" or "Non-Utility" be shown, with items 1-3 arriving at the Total Company amount for ratemaking purposes; and, (4) each state's allocation of these costs be shown on an annual basis with a comparison of the total of the states to the starting total to identify any shortfalls or surpluses. While potentially burdensome, I would expect Company management should welcome it as a fair check to ensure that proper utility costs are captured in rates. Similarly,

I would expect that regulators should welcome an audit trail and a level of transparency into the systemwide allocation of costs.

Q. IS YOUR RECOMMENDATION IN THIS CASE INFLUENCED BY THE COMPANY'S QUESTIONABLE DATA?

A. Yes. If each state's ROO Reports are based on different total Company data, it is impossible to determine whether costs are properly allocated. Put differently, we must first know what the Company's costs are before we can divide them among the states. Rejecting the 2026 Protocol and ordering parties to collaborate on an alternative will allow time for the Company (with stakeholder input) to provide a consistent and transparent audit trail of Company costs, as discussed above.

Q. WHAT DO YOU CONCLUDE OVERALL FROM YOUR ANALYSIS?

A. The 2026 Protocol is designed to resolve the issues created by PacifiCorp's historic support of a different allocation approach in Washington and the issues created by the Washington climate legislation. The 2026 Protocol is not designed to promote the interests of Utah customers or Utah policymakers. In the section below I will explain how the Company seeks to solve its Washington problems at the expense of Utah customers and why the 2026 Protocol is a bad, or at least unproven, deal for Utah.

VI. 2026 PROTOCOL / WASHINGTON 2026 PROTOCOL

Q. DOES THE 2026 PROTOCOL RELY ON THE 2020 PROTOCOL METHODOLOGY AS A BASIS FOR SOME OF THE FACTORS GOING FORWARD?

A. Yes. The 2026 Protocol relies, in part, on the unilateral continuation of a methodology negotiated by a significant number of parties in multiple states. Years of discussions went

into the development of the 2020 Protocol, with parties negotiating and trading value considerations or making concessions to reach the settlement agreement. The 2020 Protocol is a durable method that has lasted for six years. However, it was based on negotiations and trade-offs among parties.

Q. WAS AN EXTENSION OF THE 2020 PROTOCOL OR ANY OF ITS PROVISIONS, ALLOCATION FACTORS, OR GOVERNANCE AGREED TO BY ANY SIGNATORY TO THE 2020 PROTOCOL?

A. No, not to my knowledge.

Q. SHOULD THE COMPANY'S PROPOSED CONTINUATION OF SOME OF THE FACTORS FROM THE 2020 PROTOCOL BE AUTOMATICALLY ACCEPTED AS REASONABLE?

A. No. If you take the 2020 Protocol apart and start to modify certain pieces while keeping other pieces the same, it does not necessarily follow that remaining pieces are consistent with cost-causation principles or in the public interest. Thus, the Commission should carefully consider components of the 2020 Protocol that the Company unilaterally proposes to continue. Additionally, the Commission should carefully consider the key components of the 2020 Protocol that the Company, without stated rationale, does *not* propose for continuation, such as the Oregon and Idaho ECD Adjustments,[30] the Reassignment of Coal-Fueled Interim Period Resource process,[31] and the Wyoming Qualifying Facility ("QF") credit adjustment,[32] all of which were key components for various parties in agreeing to the 2020 Protocol.

[30] 2020 Protocol, p. 14, Section 3.3.2.1., lines 299-301.
[31] *Id.* at pp. 23-26, Section 4.2, lines 483-539.
[32] *Id.* at p. 30, Section 4.4.1.1, lines 629-36.

A. Tables 1 and 2 of Company Witness McCoy Revisited

Q. PLEASE SUMMARIZE THE COMPANY'S ESTIMATED IMPACT OF CHANGING FROM THE 2020 PROTOCOL TO THE 2026 PROTOCOL FOR THE FIVE STATES.

A. The Company's results are summarized in the Direct Testimony of Company witness Shelly E. McCoy in Tables 1 and 2. The tables reflect the difference for the Five States for generation categorized into the allocation buckets for "SG5A–JB 1&2 and Renewables," "SG5B–Thermal," and "SG5C–Rolling Hills," as well as a single line in Table 2 for the "NPC Impact." These components are summed and then added to the change to the "SO Allocation Change Rev. Req. Impact," or overhead changes, in order to then reflect the Five State estimated revenue requirement impact. Due to the methodology change, the results reflect the estimated rate increase for the Five States of approximately $49.3 million.

Q. DO YOU HAVE CONCERNS WITH THE COMPANY'S CALCULATIONS AND THE INFORMATION IN MS. MCCOY'S TABLES 1 AND 2?

A. Yes. My first concern is transparency. The Commission should look for a complete picture of how the Company's costs are being allocated. But PacifiCorp's approach excludes the Washington 2026 Protocol results as well as the FERC jurisdiction. The Company provides no evidence on the starting point for each state under the 2020 Protocol or the ending point under the 2026 Protocol, only the delta in between. This incomplete picture raises the question of whether the Company has properly factored into the analysis the Oregon and Idaho ECD Adjustments or the Wyoming QF Adjustment that PacifiCorp proposes to eliminate beginning in 2026. These are changes from one method to another and should not be ignored as they pertain to valuable issues that are being eliminated and

that are specifically tied to allocations. Additionally, the analysis ignores the FERC jurisdiction and that should be included even though small in comparison.

Q. ARE THERE OTHER ISSUES THAT SHOULD BE INCLUDED IN THE ANALYSIS?

A. Yes. Since this case is focused on Washington's exit from coal, the analysis should include the impact of reallocating the Bridger Coal Company investment. This asset is jointly owned with Idaho Power Company. It is not included in the Company's electric plant in service, but added to rate base as an adjustment to unadjusted results. Because Washington is exiting any coal plant on the west side of the Company's system, including Bridger, approximately 7.5% of the Bridger Coal Company investments will not be paid for in Washington rates and would be part of the unallocated assets. The Company proposal would reallocate it to the Five States and the impact of that change should be (but is not) reflected in the analysis.

Q. HAVE YOU PREPARED AN ANALYSIS THAT ADDRESSES THESE ISSUES AND PRESENTS A HOLISTIC PICTURE FOR THE SIX STATES AND BY ALLOCATION ISSUE?

A. Yes, to the extent possible. Table JKL-5 presents information similar to Ms. McCoy's Tables 1 and 2 in a comprehensive format that includes FERC, although small, that allows the comparison to total results for certain categories. Unfortunately, the Company was unwilling or unable to provide the Washington results to enable UTLCG's analysis of a comprehensive picture of the impact on a total Company basis. Table JKL-5 presents the difference, or delta, between the 2020 Protocol and the 2026 Protocol, and includes the SO factor change in a single chart as compared to Company witness Ms. McCoy's in her Tables

1 and 2. The results are as follows:

Table JKL-5[33]

Revenue Requirement Impact – Restated from McCoy Tables 1 and 2

		Generation Revenue Requirement Impact - Restated from MCCoy Table 2							
		DIFFERENCE - 2020 Protocol Compared to 2026 Protocol (000's)							
		CA	OR	WA	UT	ID	WY	FERC	Total
1	SG5A - JB 1&2 / System Renewables	(40)	(801)	2,832	(1,381)	(185)	(424)	(1)	(0)
2	SG5A - Thermal NPC	(24)	(122)	-	(1,053)	(349)	(1,662)	0	(3,210)
3	SE5A - Thermal NPC	(9)	(178)	-	(316)	(44)	(109)	(0)	(657)
4	Total	(74)	(1,101)		(2,750)	(578)	(2,196)	(0)	(3,867)
5	SG-5B - Thermal	512	10,133	(35,845)	17,480	2,341	5,370	8	(0)
6	SG5B - Thermal NPC	986	20,981	-	28,965	4,002	8,994	155	64,083
7	SE5B - Thermal NPC	1,063	20,657	-	36,534	5,116	12,656	16	76,042
8	Chehalis Situs Adjustment	(1,629)	(31,740)	34,391	(55,943)	(7,787)	(19,081)	(25)	(81,814)
9	Total	932	20,032	(1,453)	27,036	3,672	7,940	154	58,312
10	SG5C - Rolling Hills	(5)	(5,307)	5,559	(171)	(23)	(53)	(0)	0
11	SG5C - NPC	-	(3,351)	-	-	-	-	-	(3,351)
12	Total	(5)	(8,657)	5,559	(171)	(23)	(53)	(0)	(3,351)
13	Oregon Incremental Steam	-	(704)	-	-	-	-	-	(704)
14	Bridger Coal Company Rev Req.	3	68	(241)	117	16	36	0	0
15	Wyoming QF Credit Eliminated	-	-	-	-	-	7,175	-	7,175
16	Total Generation	857	9,638	3,864	24,232	3,086	12,902	154	57,566
17	System Overhead	2,263	(548)	(731)	(629)	(534)	186	(5)	(0)
18	Oregon / Idaho ECD Eliminated	-	11,000	-	-	(836)	-	-	10,164
19	Total	3,119	20,090	3,133	23,604	1,716	13,088	148	67,730
				Incomplete Data					
20	Total NPC Impact	387	6,248	-	8,188	937	798	146	
21	Present Revenues - December 2024 ROO	$135,613	$1,604,699		$2,266,222	$346,542	$692,325		
22	Est. Average Rate Impact	2.30%	1.25%		1.04%	0.50%	1.89%		
Notes:									
1	Bridger Coal Adj = $38,453,528 * 8.38% ROR								
2	See UTLCG 5.13 RAM Dec 2024 Results WY.xlsx								
3	Total Bridger Coal Adjustment at 12/31/25 per the Wyoming ROO p. 8.3			38,453,528					
	Pre-Tax ROR of 8.38%			3,222,406					
	Washington Allocation on WIJAM			690,024					
4	Trapper Mine is not included in the analysis, but is typically added to RORs in all states. WA does not pay for the Trapper Mine costs.								

Q. WHAT DOES YOUR ANALYSIS IN TABLE JKL-5 INCLUDE?

A. I have included adjustments for Bridger Coal Company, the Wyoming QF credit adjustment, and the Oregon and Idaho ECD adjustments that are part of the 2020 Protocol. As additional information is analyzed, additional updates to Table JKL-5 may be necessary. Further, Table JKL-5 does not provide a complete picture of total Company costs since the impact of Washington NPC are not included.

Q. WHAT DOES TABLE JKL-5 SHOW?

A. Table JKL-5 shows that a more holistic (yet still imperfect) calculation of cost impacts of the 2026 Protocol is higher than represented in Tables 1 and 2 of Ms. McCoy's testimony.

[33] The Company has not provided data to compare the delta from the WIJAM to the 2026 Protocol. Further analysis and discovery are warranted as the Company was unable or unwilling to provide the data prior to preparing this testimony.

For Utah specifically, while my current calculation is similar to the Company's results, I have continuing concerns on whether depreciation has been properly handled for the plants being exited and reassigned to Utah. I address the issues surrounding depreciation in more detail in the next section of my testimony.[34] Further, given that no state ROO Report results match one another on a total-Company basis,[35] it is impossible to definitively state which total-Company results should form the basis for allocation of system costs.

VII. ISSUES WITH THE 2026 PROTOCOL

Q. ASIDE FROM THE QUESTIONABLE COST IMPACT ANALYSIS YOU IDENTIFY ABOVE, HAVE YOU IDENTIFIED SPECIFIC ISSUES RELATED TO THE 2026 PROTOCOL?

A. Yes, many. I have significant concerns regarding the basis of the Company's proposal, depreciation treatment for plant exits, the contemplated Phase 2, and the allocations of Chehalis, Rolling Hills, Hermiston, new generation resources, transmission, NPC, system overheads, and gain or loss on sale of assets. The discussion below will address these concerns in turn.

A. Basis of Proposal

Q. PLEASE ADDRESS YOUR CONCERNS WITH THE BASIS OF THE COMPANY'S PROPOSAL.

A. The 2026 methodology is based on the implicit (and incorrect) supposition that the non-Washington states accept the Washington 2026 Protocol as the starting point for their cases.

Q. DOES THE COMPANY'S PROPOSAL PUT WASHINGTON INTERESTS FIRST?

A. Yes. We can see this in several important components of the Company's proposals.

[34] *Infra*, Section VII(B).
[35] *See* Exhibit JKL-3; *see also* discussion *supra* pp. 26-28.

First, the 2026 Protocol requires the Five States to acquiesce to Washington laws on generation portfolios by giving Washington preferential treatment on generation resources to meet Washington's climate laws. This includes the asset swap of Chehalis for unallocated generation and using a four-year average (2020-2023) of the System Generation ("SG") factor that is fixed at a higher level than the current allocation percentage to game the system and provide Washington with a greater allocation of intermittent, zero carbon resources to meet Washington compliance requirements. This fixed SG factor for Washington[36] is hard coded in the calculation of the SG factor to lock in its higher allocation of intermittent resources. The 2024 SG factor for Washington is 7.47%, whereas the 2020-2023 four-year average fixed-SG factor is 7.90% (0.43% higher). This difference is important because Washington load *declined* from 2020 to 2023, so current dynamic allocation factors would allocate fewer intermittent resources to Washington to meet their energy policies. This is a bad precedent and will result in an allocation mismatch if the Five States continue with a six-state dynamic allocation of these costs. Furthermore, the use of a fixed SG Factor for *all states* based on four-year averages was a component in the Resolved Issues Section of the 2020 Protocol, but would only be in effect if an agreement was reached for a Post-Interim Period Method.[37] Using this approach to fix the allocation of certain resources to one single state is problematic to say

[36] 2026 Washington Protocol Order, pp. 53-54, ¶ 168: "For the SG-F factor, while we recognize the arguments of PacifiCorp and AWEC might well be true, we also recognize that we are the first state to make a decision on the 2026 Protocol. Certainly, it is possible that other states may make decisions regarding resources currently allocated to those states or Washington which may impact Washington's allocation. For example, a state currently assigned a portion of Chehalis may not be willing to relinquish that allocation. Similarly, states may be unwilling to be assigned Washington's share of Hermiston. It is also possible that after other states make decisions on the 2026 Protocol, there may be additional non-emitting resources to be allocated to Washington. While it may be that none of these possibilities comes to fruition, we cannot reasonably fix Washington's SG-F without knowing how other states decide on the 2026 Protocol. Accordingly, we find it appropriate to allow the parties to revisit the SG-F and SO factors in future proceedings, including Phase 2.

[37] *See Id.* at p. 88, ¶ 306.

the least.

Second, the 2026 Protocol requires the Five States to make up the difference in cost allocation shortfalls previously caused by the Company's agreement to the WCA/WIJAM allocation methodologies that did not cover the Washington share under a system allocation. Further, the proposal calls for making the Company whole by allocating to the Five States the generation nominally allocated to Washington under the 2020 Protocol but never included in Washington rates, leaving the Five States to compensate for the Company's decision to put Washington's interests first.

Third, as previously mentioned, the 2026 Protocol is framed as one allocation methodology with two distinct portfolios intended to deliver 100% cost recovery for the Company's (not customers') benefit to comply with Washington state policy. However, nowhere in the Company's case does it present the total Company view of cost allocations for each of the six states (and FERC) with each state's share adding up to the total, both under the 2020 Protocol and the 2026 Protocol (with the Washington 2026 Protocol as a subset of the "one methodology"). The Company's approach in Ms. McCoy's testimony is to present the incremental bill to the Five States only *after* Washington's needs have been satisfied, and without a comprehensive review of revenue requirement.

Finally, had the Company intended to create a comprehensive and evidence-based allocation methodology, it would have provided support for all cost allocation components. Specifically, the 2020 Protocol was negotiated with many puts and takes. The Company proposes to maintain many aspects of the 2020 Protocol, and the aspects it proposes to change relate only to addressing Washington needs and eliminating Five State incentives for agreeing to the 2020 Protocol, such as the ECD Adjustments of the Wyoming QF

Adjustment that improve Company earnings. For example, the Company provides no evidence to support the key cost causation drivers in the adoption of the SC, SG, and ST allocation factors (*i.e.*, 12-CP, 75% capacity and 25% energy weighting) and its use as the primary driver for both generation and transmission costs. While this approach has been used for a long period of time, it is still based on the post-merger negotiated allocation process, and the Company provided no evidence on why it should continue and whether it supports current cost causation. It may be reasonable to continue to use this factor if an allocation approach can be accepted by all of the Five States, but from a Utah-specific perspective it may be appropriate to revisit this factor. In particular, I discuss transmission cost allocation in detail below.

Q. DOES THE COMPANY'S DECISION TO PUT WASHINGTON INTERESTS FIRST CAUSE YOU CONCERN FOR FUTURE ALLOCATION ISSUES?

A. Yes. The Company's proposal is a stop-gap approach to address Washington issues while putting off (and potentially worsening) looming issues related to Oregon and its exit from coal. Specifically, the Company's proposal shifts additional shares of coal plants to Oregon, which has already issued Exit Orders for many of these same plants. It may potentially cause problems for Oregon to address the incremental accelerated depreciation for their new share of coal plants before exiting by 2030.

Because similar issues are on the horizon with Oregon's exit from coal, this is a test case. An exiting state should not take precedence in interstate cost allocation with other states left holding the bag. A durable and holistic approach must be used, and the Company's proposal that puts Washington's interests first is not it.

B. Depreciation Reserve Upon Plant Exits

Q. PLEASE ADDRESS YOUR CONCERNS WITH PLANT EXITS.

A. There are unanswered issues regarding the plant balances when a state "exits" a resource for allocation purposes and costs are reallocated to the remaining states.

Q. PLEASE EXPLAIN HOW THE COMPANY BOOKS DEPRECIATION EXPENSE.

A. Depreciation costs for coal and gas plants are booked for financial purposes on a total Company basis and not booked by state-by-state allocation or what is recovered in rates.[38] This leads to the situation where a state's share of a plant that they have exited potentially remains for other states to pay. This could occur if accelerated depreciation expense was recovered in rates but taken to revenues with no corresponding expense on the financial books. If that is the case, the Company received a revenue windfall in prior years to cover an expense to be booked in the future (violating the accounting matching principle). That can lead to those amounts being wrongly allocated to the other states. In Company witness Shelley E. McCoy's Table 2, it appears that an adjustment is made to reflect the incremental impact of ($0.7) million on coal due the changes in allocation methods, but no adjustment is reflected for accumulated depreciation balances that will offset plant balances when a state exits coal.

[38] *See* Response to UTLCG Data Request 4.5 (provided in Exhibit JKL-5): "Depreciation expense and accumulated depreciation are not recorded on the Company's accounting books based on what is included in rates but rather based on approved depreciation rates. Therefore, the accumulated depreciation is not recorded by state, but rather in total for the Company. Accordingly, a WIJAM net book balance of Jim Bridger Unit 3, Jim Bridger Unit 4 and Colstrip Unit 4 projected through December 31, 2025 is not readily available." *See also* Exhibit JKL-4, p. 4, Oregon Results of Operations – December 2024, which demonstrates the addition to Oregon revenue requirement of $16.98 million of depreciation expense and an adjustment to accumulated depreciation of $306.6 million.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes. As shown in Exhibit JKL-4, in the 2024 Oregon Regulatory Adjustments Model, Adjustment 6.5 includes $17.0 million in increased Oregon steam depreciation expense and associated accumulated depreciation.[39] An increase in coal depreciation relative to other states started in 2008. This adjustment would impact revenue requirement and, ultimately, rates with an increase to Company income and no corresponding expense in actual financial results if only done as a regulatory adjustment. If no adjustment was made to the financial records, either the Oregon portion of the coal plants should be written down at the time of their exit, or a regulatory liability should be established for the accelerated depreciation that would then be amortized over the remaining life of the coal plants for other states at the time of exit. At this time, it is unknown if this was done. Exhibit JKL-4 (and shown later in Table JKL-7) includes $17.0 million in increased Oregon steam depreciation expense and associated accumulated depreciation of $306.6 million made in those states' ROO Report results as adjustments in the depreciation tab of the reports. The Company's explanation for the adjustments states:

> This adjustment increases depreciation expense in Oregon actual results for the year ended December 2024 to reflect the net impact of the different depreciation rates Oregon is using for the coal-fired generating plants. This treatment was approved in the 2018 Depreciation Study. [40]

This adjustment would have impacted revenue requirement and ultimately rates with an increase to Company income and no corresponding expense in actual financial results if only done as a regulatory adjustment. A similar issue exists regarding Washington because the same adjustment (Exhibit JKL-4, pp. 2-3) exists in the

[39] *See* Attachment UTLCG 5.13, Workpaper RAM Dec 2024 Results OR.xlsx, Tab Depr, p. 6.5 (provided in Exhibit JKL-4, p. 4).
[40] *See id.*

Washington ROO Report demonstrating that funds for coal plant closure have been included in earnings demonstrations and ultimately in rates. But, again, there is no indication that this change was flowed through to the financial records.

The same treatment described above for Oregon should be applied to the Washington accelerated depreciation for Bridger 3 & 4 and Colstrip 4 at issue in this case if similar accounting has not transpired. There is some indication that the Company has tracked the tax consequences of the accelerated depreciation, but it appears that those impacts have not been included in Ms. McCoy's analysis.[41] Additional investigation into these issues is warranted or a response from the Company should be provided on the accounting treatment and total amounts necessary for adjustment.

Q. IF THE COMPANY HAS NOT MADE AN APPROPRIATE ADJUSTMENT TO THEIR FINANCIAL RECORDS AS YOU SUSPECT, HAVE YOU ATTEMPTED TO CALCULATE THE IMPACT OF MAKING THE APPROPRIATE ADJUSTMENT?

A. Yes. In Table JKL-6 below, I replicate Table JKL-5 and include an estimated revenue requirement credit impact of $13.6 million related to $162.0 million of Washington allocated accumulated depreciation.

[41] For example, Shelly E. McCoy's workpapers include a section for accumulated deferred Income taxes which shows adjustments for accelerated depreciation, but those amounts are not included in the analysis supporting Ms. McCoy's Tables 1 and 2. Some level of tracking of the impacts of the accelerated depreciation for plant exits is available to the Company. *Compare* Direct Testimony of Shelley E. McCoy, p. 2, line 31, Table 1 and p. 5, line 103, Table 2 *to id.* at Workpaper 340936RMPAtt2SEMWrkprs8-5-2025.xlsx, Tab YE 2024 ADIT.

Table JKL-6

Generation Revenue Requirement Impact – Including Washington Accumulated Depreciation Reserves: Difference – 2020 Protocol Compared to 2026 Protocol

	Generation Revenue Requirement Impact - Including Washington Accumulated Reserves DIFFERENCE - 2020 Protocol Compared to 2026 Protocol (000's)								
		CA	OR	WA	UT	ID	WY	FERC	Total
1	Totals From Table JKL-5	3,119	20,090	3,133	23,604	1,716	13,088	148	64,898
2	Accum Depr - Bridger / Colstrip - est.	(190)	(3,687)	13,574	(6,522)	(913)	(2,259)	(3)	(0)
3	Total	2,929	16,402	16,707	17,082	803	10,829	146	64,898
4	Present Revenues - December 2024 ROO	$135,613	$1,604,699		$2,266,222	$346,542	$692,325		
5	Est. Average Rate Impact	2.16%	1.02%		0.75%	0.23%	1.56%		
Notes:									
1	Accumulated Depreciation - Bridger / Colstrip estimate from Exhibit JKL-4, $162m X pre-tax ROR of 8.38% is ($13.6) million Includes Colstrip 4 and Bridger Units 3 and 4 from the WA ROO report, adjustment 6.5 for 2024								
2	The adjustment does not include an additional year for 2025 accelerated depreciation of $15.4 million if that is the amount in 2025 to fully depreciate the WA share of these plants under the WIJAM method. This would need to be added to any final balance for the removal of these plants for assignment to the PacifiCorp - Subscription category of unallocated plant								

Q. WHAT DOES TABLE JKL-6 SHOW?

A. If the depreciation expense Washington has paid is used to buy down the plants included in Washington rates, as it should, then the impact to Utah is $17.1 million annually, as opposed to $23.6 million as shown in Table JKL-5. Essentially, it appears that the Company is not crediting Utah the approximately $6.5 million Washington has already paid to buy down Jim Bridger and Colstrip.

Q. SHOULD THE ACCELERATED DEPRECIATION RECOVERED FROM WASHINGTON CUSTOMERS TO PAY OFF THEIR SHARE OF BRIDGER UNITS 3 AND 4 AND COLSTRIP 4 BE USED FOR ANY PURPOSE OTHER THAN PAYING DOWN THE INVESTMENT IN THOSE SPECIFIC PLANTS?

A. Certainly not. To the extent that a state is exiting from coal or other resources and have paid off their share of the facility, those funds should be used to offset the facility costs at the time of exit. Those monies should not be applied to offset undepreciated amounts associated with other plants or even amounts associated with other plants that were depreciated but where that depreciation was not reflected in customer rates. Those are all

risks borne by shareholders – not the Company's customers in other states.

Q. HAVE YOU FURTHER ANALYZED DEPRECIATION AND THE IMPACTS OF DIFFERENT ALLOCATION METHODS ON DEPRECIATION?

A. Yes. Table JKL-7 presents the total Company generation depreciation expense ($616.0 million) underlying the Company's analysis under three separate allocation methods: (1) 2020 Protocol for all states; (2) 2020 Protocol for the 5 States and Washington on WIJAM; and (3) the current situation with the second scenario above compared to the 2026 Protocol (Five States)/Washington 2026 Protocol.

Table JKL-7

Allocation of Depreciation Expense Under Different Methods – 2024 Unadjusted Results

	Allocation of Depreciation Expense under Different Methods - 2024 Unadjusted Results							
	2020 Protocol / WIJAM /2026 Protocol & WA 2026 Protocoll (000's)							
		CA	OR	WA	UT	ID	WY	FERC	Total
	Comparison 1:								
1	2020 Protocol - All States	8,142	161,127	46,035	277,937	37,227	85,383	131	615,982
2	Washington on WIJAM	8,142	161,127	32,562	277,937	37,227	85,383	131	602,509
3	Difference - Under / (Over) Allocation	-	-	13,473	-	-	-	-	13,473
	Comparison 2:								
4	2020 Protocol - All States	8,142	161,127	46,035	277,937	37,227	85,383	131	615,982
5	Washiington on WA 2026 Protocol	8,142	161,127	33,491	277,937	37,227	85,383	131	603,438
6	Difference - Under / (Over) Allocation	-	-	12,544	-	-	-	-	12,544
	Comparison 3:								
7	2020 Protocol - All States	8,142	161,127	46,035	277,937	37,227	85,383	131	615,982
8	2026 Protocol - All States:								
9	SG5A - Renewables and Bridger 1/2	2,847	56,339	17,088	97,182	13,017	29,855	46	216,374
10	SG5B - Thermal	5,398	106,830	13,562	184,278	24,682	56,611	87	391,449
11	SG5C - Rolling Hills	106	-	2,840	3,604	483	1,107	2	8,142
12	Subtotal - 2026 Protocol	8,351	163,169	33,491	285,065	38,182	87,573	135	615,964
13	Difference - Under / (Over) Allocation	(209)	(2,043)	12,544	(7,128)	(955)	(2,190)	(3)	18
14							Five States Total		(12,527)
16	Accelerated Depreciation for Coal - 2020 Protocol:								
17	Depreciation Expense - Steam		16,979	3,145					
18	Accum. Depr Reserve - Steam								
19	Rate Base - Steam		(306,582)	(161,986)					
20	Revenue Requirement - Pre-tax ROR of 8.38%		(25,691)	(13,574)					
21	The difference in the Total column of $18,000 is primarily due to the difference in the SG5A allocation factor being fixed in WA.								

	Allocation of Depreciation Expense under Different Methods - 2024 Unadjusted Results							
	2020 Protocol / WIJAM /2026 Protocol & WA 2026 Protocoll (000's)							
		CA	OR	WA	UT	ID	WY	FERC	Total
	Comparison 1:								
1	2020 Protocol - All States	8,142	161,127	46,035	277,937	37,227	85,383	131	615,982
2	Washington on WIJAM	8,142	161,127	32,562	277,937	37,227	85,383	131	602,509
3	Difference - Under / (Over) Allocation	-	-	13,473	-	-	-	-	13,473
	Comparison 2:								
4	2020 Protocol - All States	8,142	161,127	46,035	277,937	37,227	85,383	131	615,982
5	Washiington on WA 2026 Protocol	8,142	161,127	33,491	277,937	37,227	85,383	131	603,438
6	Difference - Under / (Over) Allocation	-	-	12,544	-	-	-	-	12,544
	Comparison 3:								
7	2020 Protocol - All States	8,142	161,127	46,035	277,937	37,227	85,383	131	615,982
8	2026 Protocol - All States:								
9	SG5A - Renewables and Bridger 1/2	2,847	56,339	17,088	97,182	13,017	29,855	46	216,374
10	SG5B - Thermal	5,398	106,830	13,562	184,278	24,682	56,611	87	391,449
11	SG5C - Rolling Hills	106	-	2,840	3,604	483	1,107	2	8,142
12	Subtotal - 2026 Protocol	8,351	163,169	33,491	285,065	38,182	87,573	135	615,964
13	Difference - Under / (Over) Allocation	(209)	(2,043)	12,544	(7,128)	(955)	(2,190)	(3)	18
14							Five States Total		(12,527)
16	Accelerated Depreciation for Coal - 2020 Protocol:								
17	Depreciation Expense - Steam		16,979	3,145					
18	Accum. Depr Reserve - Steam								
19	Rate Base - Steam		(306,582)	(161,986)					
20	Revenue Requirement - Pre-tax ROR of 8.38%		(25,691)	(13,574)					
21	The difference in the Total column of $18,000 is primarily due to the difference in the SG5A allocation factor being fixed in WA.								

Q. DOES TABLE JKL-7 IDENTIFY A SHORTFALL IN COST RECOVERY FROM WASHINGTON RELATED TO GENERATION DEPRECIATION?

A. Yes. Table JKL-7 presents three scenarios on allocations of the depreciation expense category. Comparison 1 is based on allocating depreciation expense for all states on the

2020 Protocol method compared to Washington using WIJAM. Comparison 2 again uses the 2020 Protocol for all states compared to Washington on the Washington 2026 Protocol. Comparison 3 relies on the 2020 Protocol for all states compared to all states being on the 2026 Protocol. Under both Comparison 1 and Comparison 2 in Table JKL-7, a cost recovery shortfall exists due to Washington being on a different allocation method from the other states in the amount of $12.5-$13.5 million. Comparison 3 also reflects a shortfall in Washington, but that shortfall is covered by the other states being over-allocated costs in the amount of $12.5 million. This over-allocation of depreciation expense to the Five States and FERC, closes the gap in what the Company is currently experiencing, at least relative to plant depreciation, in the $13.5 million range that was originally caused by Washington. The information in Table JKL-7 also helps to understand how the Five States could be facing price increases totaling $49.3 million, with $12.5 million coming from plant depreciation expense.

Q. DOES YOUR ANALYSIS INCLUDE THE IMPACTS ON ACCUMULATED DEPRECIATION?

A. No, not for this analysis. This is a simplified view of the allocation methods on the generation plant depreciation expense to demonstrate the impacts of the proposed allocation expense on one element of the proposed cost increase.

C. Allocation of Chehalis

Q. PLEASE ADDRESS YOUR CONCERNS WITH CHEHALIS.

A. The 2026 Protocol trades Chehalis, which is currently in Utah rates, for a share of coal and east-side gas plants that are not in rates anywhere. This was a unilateral Company decision to assign Chehalis 100% to Washington without agreement from any of the Five States,

where approximately 92.5% of the plant is currently approved and included in rates. Because this decision was entirely the Company's alone, and not the responsibility or choice of any of the Five States, the Company alone should bear any resulting financial and operating risk[42] and outcomes affecting credit.

Q. DID THE PARTIES TO THE 2020 PROTOCOL ENVISION A DIFFERENT APPROACH TO GENERATION REASSIGNMENT?

A. Yes. The 2020 Protocol included a significant process for the Company to follow if it determined that the Washington share of east-side coal and gas (and west-side coal after 2025) resources have economic value and should be proposed for reassignment in other states. The Company failed to follow this procedure and appears to be proposing to reassign the generation resources in question with Chehalis as a swap, rather than an economic and risk evaluation process contemplated by the parties to the 2020 Protocol.

D. Allocation of Rolling Hills

Q. PLEASE ADDRESS YOUR CONCERNS WITH ROLLING HILLS.

A. The Company proposes that Oregon's 26% disallowed share of the Rolling Hills wind plant be assigned to Washington. However, because the 2026 Protocol also proposes that Washington's share of Rolling Hills becomes fixed, the Utah dynamically allocated share of Rolling Hills will be impacted. This increases risks to Utah in so far as Utah would no longer enjoy the benefits of an increased share of the Rolling Hills output if Utah loads grow on a relative basis or a decreased share if Utah loads decline on a relative basis. There should be a thorough analysis of the costs and benefits of this change before it is accepted.

[42] The potential exists for a 192% overallocation of a 518 MW thermal resource and an open generation position.

E. Allocation of Hermiston Gas Plant

Q. PLEASE ADDRESS YOUR CONCERNS WITH THE HERMISTON GAS PLANT.

A. The 2026 Protocol proposes that Washington's share of the Hermiston gas plant be removed from Washington and reassigned to the Five States through the SG5B allocation factor, increasing the relative share to the Five States and zeroing out Washington share.[43] PacifiCorp does not argue that the Hermiston plant cannot comply with current state laws. This should be rejected as part of the 2026 Protocol and the Commission should not accept the reassignment of this plant without a thorough analysis of the costs and benefits attributed to it, which analysis PacifiCorp has not presented to the Commission.

F. Allocation of New Generation Resources

Q. PLEASE ADDRESS YOUR CONCERNS WITH NEW GENERATION RESOURCES.

A. The 2026 Protocol does not provide a durable, long-term solution for the allocation of new generation resources. Company witness Rick T. Link states: "The Company will propose an allocation for new resources with a term or depreciable longer than three years at or before the time when a prudence review occurs."[44] For Washington, new generation will be situs assigned after April 1, 2025.[45] However, the Company has given no clear guidance for what that means for the Five States operating under a "single" methodology. Will all new generation be situs assigned after April 1, 2025, or does each state get to decide what its share of an allocation is at the time of a prudence review? This question is unanswered by the Company's proposal.

[43] *See* Response to UTLCG Data Request 7.4 (provided in Exhibit JKL-5).
[44] Direct Testimony of Rick T. Link, p. 24, lines 480-481.
[45] 2026 Washington Protocol Docket, Direct Testimony of Rick T. Link, Exhibit No. RTL-1T, p. 3, lines 9-14.

G. Allocation of Transmission

Q. PLEASE ADDRESS YOUR CONCERNS WITH TRANSMISSION ALLOCATIONS.

A. Company witness Rick T. Link indicates that in Phase 2 of the Company's 2026 Protocol proposal additional elements may be addressed, including transmission costs. A system using multiple generation portfolios must address the transmission cost causation and implications of such a system. If each state uses an increasingly differentiated generation portfolio, transmission that delivers that diversified generation to load cannot ignore that reality. But the Company's proposal does ignore that reality until some point in the future.

Q. SHOULD THE COMMISSION BE CONCERNED WITH TRANSMISSION BUILT SOLELY TO SUPPORT A SPECIFIC GENERATION PLANT?

A. Yes. In the Company proposed Washington 2026 Protocol, it stated:

> As identified in section 4.2.1 of the WIJAM, PacifiCorp has already excluded transmission that is used primarily for the transmission of power from generation assets that are not assigned to Washington under the West Control Area interjurisdictional cost allocation methodology.[46]

The Commission should be vigilant to the potential situation that significant transmission is built to deliver intermittent, non-emitting generation assigned to a particular state due to policies requiring such generation and to gain the best possible capacity factor and economics out of the generation resources, while socializing and system allocating the transmission delivery costs. If out of state generation is developed to take advantage of higher capacity factors, a reasonable share of the associated transmission costs should be allocated to the state making that choice.

[46] *Id.* at p. 6, lines 10-16, n.5.

Q. HOW DOES THE COMPANY PROPOSE TO ALLOCATE TRANSMISSION COSTS IN THE 2026 PROTOCOL AND FOR WHAT REASON?

A. The Company proposes continuing the current practice of allocating transmission similar to generation using the 2020 Protocol derivation of the SG Factor. The 2020 Protocol methodology is a weighting of the demand component (12 CP) by 75% and the energy component by 25%. The SG Factor was applied to both generation and transmission related costs as part of settlements on allocation methods for many years:

> The Company continues to support the proposed 2026 Protocol allocation of transmission assets under the system generation (SG) allocation factor. This treatment is consistent with the allocation factor used and approved in many past cost allocation agreements, including the most recently approved 2020 Inter-Jurisdictional Cost Allocation Methodology (2020 Protocol) as filed in Docket No. 19-035-42. Note: transmission was also considered a resolved issue as identified in Section 5.2 in the 2020 Protocol and would continue to be allocated using the System Transmission (ST) allocation factor, which is calculated the same as the SG allocation factor as proposed in Phase I of the proposed 2026 Protocol. Absent a compelling reason to change, minimizing changes from current allocation practices will aid in implementation of the proposed 2026 Protocol and help reduce cost shifts among states.[47]

Q. DOES THE CLAIM THAT THE TRANSMISSION ALLOCATION WAS A "RESOLVED ISSUE" IN THE 2020 PROTOCOL CARRY ANY WEIGHT?

A. No. The preamble of the 2020 Protocol's Resolved Issues expressly states:

> The Parties agree, conditioned upon reaching agreement on a Post-Interim Period Method on the future allocation treatment described in this Section 5 for certain benefits, revenues, costs, and investments. As stated in Section 2 these Resolved Issues of the 2020 Protocol are intended to take effect with the implementation of the Post-Interim Period Method. Parties acknowledge that conditions may change materially in unforeseen ways during the Interim Period and that it may be necessary to re-evaluate Resolved Issues as part of the Post-Interim Period Method.[48]

No agreement was reached on a Post-Interim Period Method and, therefore, there

[47] Response to UTLCG Data Request 2.44, subpart a (provided in Exhibit JKL-5).
[48] 2020 Protocol, p. 32, Section 5, lines 659-664.

is no binding agreement on any items in the Resolved Issues section of the 2020 Protocol. Further, the 2026 Protocol and events that have transpired since the Company discontinued the MSP Framework Issues Workgroup have resulted in a need to re-evaluate Resolved Issues.

Q. WHAT WAS THE JUSTIFICATION FOR THE 12 CP, 75% CAPACITY AND 25% ENERGY COMPONENTS OF THE SG FACTOR?

A. A PacifiCorp analysis provided to the PacifiCorp Multi-State Process ("MSP") in 2003 states the following:

> A wide variety of classification and allocation options are currently used by utilities across the country and Utah Power, Pacific Power and PacifiCorp have used several different methods in the past. Many of these methods, as well as a number of new alternatives have been discussed during MSP. Of the total system allocation options, the classification of plant between demand and energy components seems to have the largest impact on state revenue requirements. Larger energy classifications assign more costs to high load factor states while larger demand classifications assign more cost to lower load factor states. The choice of the 75% demand 25% energy classification for generation and transmission plant was the last allocation decision made by [the PacifiCorp Interjurisdictional Taskforce on Allocations] after the merger.[49]

Q. WHAT IS THE COMPANY'S JUSTIFICATION FOR TRANSMISSION ALLOCATION FOLLOWING THE TREATMENT FOR GENERATION?

A. The Company states:

> Transmission assets typically deliver generation level voltage to lower level distribution system assets. As such, transmission assets have been based on allocation factor characteristics similar to that of generation assets as discussed further in the Company's response to UTLCG Data Request 2.34.[50]

[49] Response to UTLCG Data Request 2.34, Attachment UTLCG 2.34, Dave Taylor, *Classification and Allocation of Generation Fixed Costs Discussion Paper* (March 4, 2003) (provided in Exhibit JKL-5).
[50] Response to UTLCG Data Request 2.44, subpart b (provided in Exhibit JKL-5); *see also* Response to UTLCG Data Request 2.34 (provided in Exhibit JKL-5).

Q. IS THERE A COMPELLING REASON TO DEPART FROM THE CURRENT PRACTICE?

A. Yes. Merger benefits from over 35 years ago should be less of a concern than the future concerns with cost causation from a system that will be devolving into multiple generation portfolios to address state policy requirements and the transmission necessary to serve load from the generation portfolios. If you take PacifiCorp's argument at face value, and generation portfolios will have situs assigned generation, then the transmission component would follow plant and have a weighted component for generation that is situs, or state specific. For Washington, the Company proposed "the situs assignment of new resources identified for Washington after April 1, 2025."[51] To the extent possible, transmission allocations should remain on a system basis, but the link to generation is changing and the allocation method should also be revisited to better track cost causation, similar to how the costs of the transmission system are charged to third-party transmission users. I present a proposed solution in the next section of my testimony.

Q. DO YOU HAVE ANY ADDITIONAL CONCERNS RELATED TO THE COMPANY'S PROPOSAL AND IMPACTS ON TRANSMISSION?

A. Yes. The Company currently has a disallowance imposed by the Oregon Public Utility Commission related to the prudence of the Gateway South Transmission Line in the amount of $16.2 million. The Oregon Commission stated that

> Additionally, observing that PacifiCorp continues to rely on significant modeled NPC benefits in this case, again referencing the analysis from docket UM 2059 of coal plant displacement as justification for Gateway South, we reprise our concerns as stated in docket UM 2059. As the project already has questionable economics, the benefits that are presented in this case are critical

[51] 2026 Washington Protocol Docket, Direct Testimony of Company witness Rick T. Link, Exhibit No. RTL-1T, p. 3, lines 9-14.

to actually achieve. In docket UM 2059, while acknowledging the final short list we said,

> We noted that the emissions reductions associated with the final shortlist are an important additional benefit that is additive to the capacity and energy benefits. The final shortlist has been shown as a cost-effective plan that also significantly reduces PacifiCorp's greenhouse gas emissions. We discussed how the emissions reductions from the final shortlist are dependent on the dispatch of PacifiCorp's thermal plants as the modeling shows the thermal fleet flexing to enable the economic value from the new resources for customers. We stated that we rely on the modeled emissions reductions as a benefit that supports our acknowledgement.[52]

My concern is that the Company has proposed reassigning significant coal generation to the Five States (including Oregon between 2026-2029) in 2026 and an additional tranche potentially in 2030 while receiving guidance from Oregon to reduce greenhouse gas emissions to eliminate the $16.2 million disallowance.[53] One of two outcomes appear likely if the plants are reassigned as proposed under the 2026 Protocol: (1) the plants continue to operate *status quo* and emissions are not reduced, and, therefore, the Oregon partial disallowance of Gateway South persists for the Company, or; (2) the Five States pay for the costs of the plants but their usage is curtailed to meet Oregon's requirements and the benefits to four states (the Five States excluding Oregon) decreases while Oregon perceives benefits related to greenhouse gas emissions and PacifiCorp can justify the elimination of its $16.2 million disallowance in Oregon. While the Oregon decision may not directly impact Utah, this situation raises the concern of how reassignment may impact how the Company operates and how costs and benefits flow to

[52] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket UE 433, Order No. 24-447, pp. 42-43 (Dec. 19, 2024) (citation omitted).
[53] *Id.* at p. 42.

the different states. None of these issues have been analyzed in any detail in the Company's proposal.

H. Net Power Costs

Q. PLEASE ADDRESS YOUR CONCERNS WITH NET POWER COSTS.

A. The 2026 Protocol creates significant issues, uncertainty, and risks to the Five States related to NPC and its tracking (through nodal pricing mechanisms ("NPM") or Energy Day Ahead Markets ("EDAM")), planning reserve margins, operating reserves, and ancillary services. The Company does not address the inclusion of coal and gas units not paid for by Washington that are being included in many of the reserve calculations, raising the question of whether the Five States are paying for the resources and carrying the rate base, but Washington gets the benefits of the operating reserves. These issues are addressed by UTLCG witness Mullins.

I. System Overheads

Q. PLEASE ADDRESS YOUR CONCERNS WITH SYSTEM OVERHEADS.

A. I disagree with the Company's proposal to change from the current cost causation, plant-based allocation factor to a simple 1/3 capacity, 1/3 energy, 1/3 distribution plant allocation. This approach should be rejected.

Q. HOW ARE SYSTEM OVERHEAD COSTS ALLOCATED UNDER THE 2020 PROTOCOL?

A. The allocation factor for the SO Factor is calculated based on the allocation or assignment of gross plant to each state, excluding any plant allocated on the SO Factor to eliminate any circular calculation. To the most rational extent possible, the Company should be coding costs and activities to the correct function. If an engineer or a lawyer is working on

a generation project, their time should be charged to the project and costs and benefits should follow the time allocation. However, other activities are not project specific and are truly an overhead activity, such as budgeting or developing business plans. These general activities, at their core, relate to how the Company manages the assets it operates to serve customers. As such, an allocation based on gross plant is reasonably tied to cost causation.

Conversely, each state's demand or System Capacity ("SC") allocator may not reasonably tie to overhead costs. For example, assume two states each have a peak load of 1000 MW but one relies on 3000 MW of intermittent resources to meet that peak need and the other relies on 1000 MW of dispatchable resources. The corporate overheads associated with managing those 4000 MW of generation are much more closely aligned with the relative plant investment in those projects as opposed to the load characteristics of each state. Similarly, the amount of energy a state consumes is less correlated to the effort necessary to manage the generation resources than the investment associated with those resources. This difference becomes increasingly important as we move forward and each state's resource mix becomes more unique to that state. Certainly no allocation is perfect. That is the nature of allocations. But the SO allocator in the 2020 Protocol has worked well, better reflects cost causation, and should remain unchanged.

Q. HAVE YOUR PREPARED A COMPARISON OF THE CHANGE FROM GROSS PLANT AS A BASIS FOR THE SO FACTOR CALCULATION TO ONE BASED ON AN EQUAL 1/3 SPLIT BETWEEN CAPACITY, ENERGY, AND SITUS DISTRIBUTION?

A. Yes. Based on 2023 unadjusted total Company ROO, the comparison in Table JKL-8

compares the change from a factor calculation based on a plant cost causation approach to one based on an equal 1/3 split between capacity, energy, and situs distribution. Table JKL-8 demonstrates a significant shift in the factor situs assignment to energy and away from both capacity and situs factors. Company witness Ms. McCoy's Table 1 reflects the shift in dollars among states relative to their proposed change. With the potential for future situs generation, the current method should be maintained for the reasons I outline.

Table JKL-8
Current vs. Proposed SO Factor

Current Vs. Proposed SO Factor			
	Current	Proposed	Change
System Capacity	53.07%	51.02%	-4%
System Energy	17.81%	39.27%	120%
Situs	28.47%	9.49%	-67%
No. of Customers	0.64%	0.21%	-67%
	100.00%	100.00%	

Q. DID THE 2020 PROTOCOL ANTICIPATE A POTENTIAL CHANGE IN THE SO FACTOR?

A. Yes, conditionally. It states:

> Costs that support more than one function, such as generation, transmission, or distribution plant, will continue to be allocated on the System Overhead ("SO") Factor after the Interim Period but will be calculated based on an equal one-third weighting of the System Capacity ("SC") Factor, System Energy Factor and System Gross Plant Distribution ("SGPD") Factor, as shown in Appendix B.[54]

However, as noted above, Resolved Issues are "conditioned upon reaching agreement on a Post-Interim Period Method on the future allocation treatment," and the

[54] 2020 Protocol, p. 35, Section 5.4, lines 734-738.

2020 Protocol specifically contemplates re-evaluation on changed circumstances.[55]

Q. ARE YOU AWARE OF ANY POST-INTERIM PERIOD METHOD AGREED TO AND IMPLEMENTED?

A. No. As a result, the SO Factor "Resolved Issue" status does not exist as the conditioned action did not take place.

Q. HAVE CONDITIONS CHANGED MATERIALLY IN UNFORESEEN WAYS SINCE 2019 WHEN THE 2020 PROTOCOL WAS NEGOTIATED?

A. Yes. The main change is the potential for significant generation that may be situs assigned or shared between a few states, such as Oregon and Washington for wind, solar, and batteries. The 2025 PacifiCorp Integrated Resource Plan ("IRP") reflects this concern in the state and system portfolios in Section 9 of Volume 1. To the extent that costs cannot be identified and explicitly charged to these activities, they should follow the overall gross plant balances as the generation plant grows.

Under the Company's proposal, if, for example, Utah's load is growing faster relative to other states, and therefore the SC and System Energy ("SE") Factors increase, Utah will get a greater share of system overhead costs even if Oregon adds thousands of megawatts of situs generation to the system causing significant indirect activity. The Company proposal weights distribution plant, which is state specific. The same concept should apply to generation and the impact of potential situs generation should be captured through the continued use of an SO Factor that is based on gross plant, not capacity and energy.

[55] *Id.* at p. 32, Section 5, lines 659-664.

Q. DO YOU HAVE OTHER CONCERNS WITH SYSTEM OVERHEAD COST ALLOCATIONS?

A. Yes. In reviewing the 2024 data, a significant portion of the costs in Administrative & General accounts are in the SO allocation category – specifically $596 million of a total $657 million.[56] Within the $596 million SO cost category, $477 million is related to Injuries and Damages allocated on the SO Factor.[57] I would recommend that the Commission order a review in the next general rate case to make sure that the costs to which an SO Factor is applied to are indirect, unclassifiable costs that belong in an overhead allocation. An easy test would be to review a sample of general office employee time sheets to see if the Company has instituted a consistent process of properly tracking activities, or if there is no time tracking and it just ends up lumped in as an overhead.[58] For Injuries and Damages, insurance allocations should be reviewed. In raising the issues now, my intent is to make sure the Company has time to do its own review and make sure that the costs are properly coded and assigned to the proper allocation factors before rate cases are filed and potentially challenged. For example, as Utah now has a pending specific process to deal with wildfire liability in the state, the Commission should ensure that Utah is not allocated overhead costs properly assigned to other state wildfire issues.

[56] Response to UTLCG Data Request 2.3 (provided in Exhibit JKL-5), Attachment UTLCG 2.3, Workpaper 2024 Results of Operations.xlsx, Tab UT ROO Report, Cells I:1045 and I:1048.
[57] *Id.* at Cell I:996.
[58] The Company has rejected any attempts to sample executive time sheets to validate the assignment of overhead costs to functions and cost allocations. *See, e.g.,* Response to UTLCG Data Request 7.6 (provided in Exhibit JKL-5); *see also* Response to UTLCG Data Request 2.45 (provided in Exhibit JKL-5).

J. Phase 2 of the 2026 Protocol

Q. PLEASE ADDRESS YOUR CONCERNS WITH THE COMPANY'S PROPOSED PHASE 2 COMPONENT OF THE 2026 PROTOCOL.

A. Depending on how the Commission decides this case, there may well be outstanding issues that need to be addressed. However, I disagree with waiting an indeterminate amount of time to resolve any remaining questions. Company witness Rick T. Link states: "The Company will present a Phase 2 filing to the state regulatory commissions to be effective no later than 2030."[59] Waiting until sometime closer to 2030 for the pending issues to be resolved is risky and may waste critical time available now. As part of this case or soon after its completion the investigation into the pending issues should be addressed.

K. Allocation of Gain or Loss from Sale of Assets

Q. SECTION 14.0 OF THE COMPANY'S 2026 PROTOCOL PROPOSAL ADDRESSES THE ALLOCATION TREATMENT OF THE GAIN OR LOSS FROM SALE OF ASSETS. DOES THIS RAISE ANY CONCERNS?

A. Yes. The 2020 Protocol states:

> 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 remained a System Resource.[60]

The Company is making a significant shift through the reassignment of generation plant in

[59] Direct Testimony of Rick T. Link, p. 16, lines 311-313.
[60] 2020 Protocol, p. 43, Section 7, lines 915-920.

its proposal, particularly with Chehalis. Had the Company waited until January 2, 2027,[61] and entered into an asset sale agreement that involves Chehalis, either as a single asset sale or as part of a Washington jurisdictional sale, the gain or loss for Chehalis would inure solely to Washington under the 2026 Protocol. If the Commission accepts a methodology that 100% assigns Chehalis to Washington, I recommend the Company proposal be modified from "less than one calendar year" to "less than three calendar years" to protect customers that have paid for the generation plant over numerous years.

Q. BASED ON THE ABOVE, WHAT DO YOU RECOMMEND?

A. The Company's proposal is a Band-Aid to address near-term Washington issues and leaves far more questions than answers, increasing costs and risks to Utah. I recommend that the Commission reject the Company's proposal.

Q. WHAT IS YOUR ALTERNATIVE PROPOSAL TO THE COMPANY'S 2026 PROTOCOL AND ITS RESULTING POTENTIAL PRICE INCREASE?

A. In the following section, I present an alternative allocation framework (the "Allocation Framework") as a concept for the Commission's consideration. I believe this framework will provide a durable path forward to permanently resolve the allocation issues, including Oregon's exit from coal in a few short years.

VIII. ALLOCATION FRAMEWORK

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR PROPOSED ALLOCATION FRAMEWORK.

A. Exhibit JKL-1 includes the Allocation Framework proposal. The Allocation Framework is presented as a basis for a new allocation method, potentially after further discussions

[61] PacifiCorp seeks to make the effective date of allocation changes January 1, 2026, through the Washington ordered date and deferrals in other states, making the trigger date for this section one year and one day from January 1, 2026.

with the Company and parties. In general, the Allocation Framework addresses allocations on a least-cost systemwide approach to the extent possible in a world where each state will end up being allocated the costs of a unique combination of generation resources being used to provide a variety of capacity and energy services. The premise of the Allocation Framework is that the states will all continue to evolve to increasingly unique generation portfolios necessitating that several fundamental allocation approaches be changed. The following items are included in the Allocation Framework, with the understanding that many details remain to be worked out and other items will also need to be addressed:

- Resource Adequacy
- Operating Reserves and Ancillary Services
- Generation
  - Existing Generation – Shared by All States
  - Existing Generation – Coal
  - Existing Generation – Gas
  - Existing Generation – Rolling Hills
  - New Generation – Shared by All States
  - New Generation – Non-System Subscription
  - QFs
- Transmission
- Net Power Costs

A. Resource Adequacy

Q. PLEASE ADDRESS THE ALLOCATION FRAMEWORK PROPOSAL ON RESOURCE ADEQUACY.

A. All states and FERC jurisdictional customers will require operating reserves and ancillary services to support their load and should be required to pay for their share of these requirements imposed on the Company. All states should pay for their impact of providing these requirements, even if they have eliminated coal or added incrementally higher intermittent resources to their portfolios. A process should be established to ensure fair and equitable treatment of operating reserves and ancillary services without one state

leaning on another for coverage without compensation. UTLCG witness Mullins provides further detail on the issues presented regarding resource adequacy.

B. Generation

Q. PLEASE EXPLAIN THE TREATMENT OF GENERATION COST ALLOCATIONS IN THE ALLOCATION FRAMEWORK.

A. The generation component is designed to allow PacifiCorp to comply with state-specific legislation while allowing for state flexibility and maximizing the state cooperation and participation in shared resources to the greatest extent possible through dynamically sharing common resources. This proposal eliminates the proposed redistribution of Washington's 7.5% share of unallocated/unassigned resources (and future Oregon shares) to the Five States and protects existing customers, while also providing an avenue for the Company to monetize any unallocated generation. This could include opportunities for the Company to use these resources to serve large-load customers without impacting the Company's remaining customers. The methodology addresses existing generation shared by all states, existing coal generation, and existing gas generation shared by all states.

C. Existing Generation – Shared by All Six States

Q. PLEASE EXPLAIN THE TREATMENT OF EXISTING GENERATION RESOURCES SHARED BY ALL SIX STATES IN THE ALLOCATION FRAMEWORK.

A. The existing generation, including power purchase agreements, that is accepted by all states will continue to be dynamically allocated using the 2020 Protocol SG factor methodology to allocate fixed costs, as applicable, and the 2020 Protocol SE factor to allocate variable costs, as applicable. Currently, this category captures all non-emitting resources, except

Rolling Hills and Bridger 1 & 2. Resources for which there is not unanimous acceptance will be treated as their own category in allocation factors. This proposal specifically rejects the Washington 2026 Protocol and the assignment of non-emitting resources to Washington on a fixed four-year average (2021 levels), with the remainder allocated to the other Five States. This proposal continues to treat Washington on a dynamic basis, and therefore, Chehalis on a dynamic system allocation. The overallocation of Chehalis to Washington in the Washington 2026 Protocol may allow the Company to minimize CCA costs, but the Company will be responsible for the cost of the overallocation of the resource in net power costs. However, the overcollection of Chehalis for plant costs (192%) will provide a revenue stream that will mitigate some of the Company's shortfall. This was the treatment in the 2020 Protocol for generation assets (*e.g.*, Bridger over-allocation). The system allocation is shown in Table 1 of Exhibit JKL-1.

D. Existing Generation – Coal

Q. HOW DOES THE ALLOCATION FRAMEWORK PROPOSE TO ALLOCATE COSTS ASSOCIATED WITH EXISTING COAL FACILITIES?

A. The Allocation Framework contemplates a new SG-1 factor for the allocation of coal costs. This SG-1 factor will be calculated in four steps:

1. First, to the extent coal generation is used to provide operating reserves or ancillary services, a fixed share of the generation will be allocated to "PacifiCorp – Reserves" as discussed in the resource adequacy section of the proposal and in the testimony of UTLCG witness Mullins. A constant share of variable O&M will be allocated to this bucket based on the same percentage, but this proposal, tentatively, will not allocate fuel costs to this bucket as the resources are generally not providing

net energy when being used for operating reserves or ancillary services. Thus, no share of any energy output or revenues will be allocated to this bucket either.

2. Second, there will be a fixed share allocated to a new bucket called "PacifiCorp – Subscription" that, effective January 1, 2026, will be equal to the Washington allocation of existing coal generation using the 2020 Protocol SG factor based on loads in 2025 shown in Table 2 of Exhibit JKL-1. That fixed share will remain constant over time. A constant allocated share of the variable costs will also be allocated to this bucket as well as a constant allocated share of the benefits of any energy output.

3. Third, there will be an additional fixed share allocated to "PacifiCorp – Subscription" effective January 1, 2030, that will be equal to the Oregon allocation of existing coal generation using the 2020 Protocol SG factor based on loads in 2029 shown in Table 3 of Exhibit JKL-1. That fixed share will remain constant over time. A constant share of the variable costs will also be allocated to this bucket as well as a constant share of the benefits of any energy output.

4. Last, the remaining shares will be dynamically allocated to the remaining five or four states, as applicable, using the 2020 Protocol SG factor for the fixed costs and a new SE factor calculated based on the energy consumption of states sharing the resource to allocate the remaining variable costs.

Q. IF A STATE EXITS AN EXISTING RESOURCE IN THE FUTURE, HOW WILL IT BE HANDLED?

A. If a state exits an existing resource in the future, PacifiCorp is responsible for ensuring that the resources are depreciated and paid for before exit (*i.e.*, when the new PacifiCorp-

Subscription bucket is established). All accelerated depreciation in Washington and Oregon prior to their respective exits from existing coal would be applied to offset the fixed costs associated with the share of the plants included in the "PacifiCorp – Subscription" bucket after they exit the resources. At a minimum, the Company should be responsible for the full depreciation of Washington's allocated share of WIJAM coal resources (*i.e.*, Bridger 3 & 4 and Colstrip) that were exited on December 31, 2025, if PacifiCorp did not choose to seek accelerated depreciation of the plants leading up to 2025.

Q. HOW WILL THE GENERATION ASSIGNED TO THE "PACIFICORP - SUBSCRIPTION" CATEGORY BE HANDLED?

A. The portion allocated to the "PacifiCorp – Subscription" bucket can be allocated or used by PacifiCorp in a number of ways. First, PacifiCorp may propose and a state may accept some or all of the capacity and associated energy as a subscription resource to meet the state's needs. Second, PacifiCorp may elect to sell some or all of the capacity and associated energy to large load customers as permitted by state law. Third, PacifiCorp may elect to sell some or all of the capacity and energy into wholesale markets or use it to serve load in Washington but not explicitly in rates as is the current practice.

Q. HOW LARGE WILL THE "PACIFICORP – SUBSCRIPTION" CATEGORY BE INITIALLY?

A. Preliminary analysis shows the initial allocation of the existing coal generation would be about 7.5% to the "PacifiCorp – Subscription" bucket. That is based on the 2024 Washington share of the SG factor. The expectation is that the "PacifiCorp – Subscription" bucket of the existing coal generation would then increase to about 33.7% on January 1, 2030, based on Oregon's 2024 loads and 26.2% SG allocation in 2024 (*see* Table 2 and 3

of Exhibit JKL-1).

Q. HOW WILL CAPITAL COSTS RELATED TO STATES' PORTIONS OF COAL PLANTS THAT ARE BEING EXITED BETWEEN NOW AND 2030 BE HANDLED?

A. Regarding capital costs associated with existing plants being exited prior to 2030, until a state exits from a resource, all plant additions will be allocated to all states that continue to receive the benefits of the plant. Once a state exits the resource, the state's share of the undepreciated capital additions will be allocated to the "PacifiCorp – Subscription" bucket. It is between PacifiCorp and the exiting state(s) whether and to what extent those costs should be paid by the state through increased depreciation prior to exit. Of course, PacifiCorp can then seek to allocate any undepreciated costs to any state or customer that agrees to subscribe to the resource going forward.

Q. HOW WILL CAPITAL MAINTENANCE COSTS RELATED TO STATES' PORTIONS OF COAL PLANTS THAT ARE BEING EXITED BETWEEN NOW AND 2030 BE HANDLED?

A. With regard to Oregon's anticipated exit from coal in 2030, for capital maintenance of the coal plants between January 1, 2026 and December 31, 2029, a *pro rata* share may be determined and included in Oregon rates as discussed above and booked to accumulated depreciation to offset the plant costs when Oregon exits coal. This should not impact allocation factors. Capital additions would need to be tracked and a method devised for Oregon ratemaking purposes between 2026 and 2030. This should not affect other states, and any differences would be captured and reflected in the "PacifiCorp – Subscription" bucket of plant costs. The same approach would be applied to any other state that chose to

exit from an existing resource.

E. Existing Generation – System Gas and East-Side Gas

Q. PLEASE EXPLAIN THE TREATMENT OF EXISTING SYSTEM GAS GENERATION.

A. Existing gas generation will be first allocated to the "PacifiCorp – Reserves" bucket as discussed above and explained by UTLCG witness Mullins. Then, the remaining capacity that is accepted by all states will be allocated using the 2020 Protocol SG factor. This would apply to Bridger 1 & 2 and Chehalis. This six-state factor would be a dynamic factor and adjust with loads. Variable costs, including variable O&M and fuel, will be allocated the same way as discussed in the Existing Coal section above. This is further depicted in Table 5 of Exhibit JKL-1.

Q. PLEASE EXPLAIN THE TREATMENT FOR EAST-SIDE GAS THAT IS EXCLUDED BY WASHINGTON.

A. Because of Washington's divisional treatment of generation resources, gas generation on the east-side of the PacifiCorp system is not included in Washington rates. Additionally, the Washington 2026 Protocol proposed and the WUTC accepted removing Hermiston from Washington rates and shifting cost responsibility for that plant to the Five States (who have not accepted it). Therefore, Hermiston would be included in this category with Washington's abandoned fixed amount assigned to the "PacifiCorp – Subscription" bucket. The development of a new SG-2 factor for east-side gas would follow the same process as used for existing coal, meaning that a portion will be assigned to "PacifiCorp – Reserves." Then, effective January 1, 2026, a 7.5% allocation would be assigned to the "PacifiCorp – Subscription" bucket and the remainder would be allocated to the Five States dynamically.

This factor would be applied to all of the east-side gas plants not included in Washington rates at year-end 2025, including Current Creek, Lakeside, Gadsby, Hermiston, and Naughton (gas peaking). Variable costs, including variable O&M and fuel, will be allocated the same way as discussed in the Existing Coal section above. This is further depicted in Table 6 in Exhibit JKL-1.

F. Existing Generation – Rolling Hills

Q. PLEASE EXPLAIN THE TREATMENT OF THE ROLLING HILLS WIND PLANT.

A. The Oregon portion of the Rolling Hills wind plant was disallowed and excluded from Oregon rates. The Allocation Framework develops a new SG-3 factor for the fixed costs associated with Rolling Hills and would follow the same process as used for existing coal except that the exiting state in this instance is Oregon. That means that effective January 1, 2026, approximately 26.2% of the plant would be assigned to the "PacifiCorp – Subscription" bucket and the remainder would be allocated to the other four states dynamically. Variable O&M would be allocated on a fixed basis to the "PacifiCorp – Subscription" bucket and then a dynamic SE basis to the states remaining in Rolling Hills. The Allocation Framework provides visibility to the asset and any state, including Washington, could elect to subscribe to the available capacity of Rolling Hills Wind (approximately 26 MW), which would be added to the state's allocation of the resource (*e.g.*, adjustment SG-3.2) as a fixed share. PacifiCorp has essentially proposed this treatment for Washington in the Washington 2026 Protocol, except that the allocation share is proposed to be fixed. Table 7 of Exhibit JKL-1 presents an example of the allocation of Rolling Hills.

Q. HOW WILL THE RELATIONSHIP BETWEEN THE "PACIFICORP – SUBSCRIPTION" BUCKET AND THE STATE ALLOCATIONS BE MAINTAINED?

A. Each year after a resource has been assigned to the "PacifiCorp – Subscription" bucket and its allocation held constant, the remaining allocation of the resource will be handled through a *pro rata* adjustment to the SG factor to maintain the fixed nature of a portion of the resource and dynamically allocate the remainder. In Table 8 of Exhibit JKL-1, a hypothetical year two example is shown where Oregon's SG increased by 0.3%. The Oregon share is reduced back to 26.2% and the difference is reallocated to the other states based on their new SG allocations. This same concept would be applied to the other resources placed in the "PacifiCorp – Subscription" bucket on a going forward basis.

Q. HOW IS THE FIXING OF FACTORS FOR THE SHARES IN THE "PACIFICORP – SUBSCRIPTION" CATEGORY FAIR TO THE COMPANY AND TO CUSTOMERS?

A. Locking in the fixed allocation of resources placed in the "PacifiCorp – Subscription" bucket allows for the proper tracking of unallocated portions of resources open for potential subscription, and does not allow the amount to shrink or grow, which is fair to the Company and to states. It also allows a defined amount of the "PacifiCorp – Subscription" resources to be allocated to states, if the states desire an increased share of those resources, or large customers that are subscribing to a specific amount of resources. Rather than trying to adjust for the annual changes in the amount of the "PacifiCorp – Subscription" resources under a dynamic factor, the Allocation Framework alleviates this issue and locks in the change in the allocation at the time it occurs, and the remainder of the plant balance would

continue to be dynamically allocated.

G. New Generation – Shared by All States

Q. PLEASE EXPLAIN THE TREATMENT OF NEW GENERATION THAT WILL BE SHARED BY ALL STATES.

A. New generation that is accepted by all states will be considered fully subscribed or apportioned, but the amount of the subscription will continue to be dynamically allocated using the 2020 Protocol SG factor for fixed costs and the 2020 Protocol SE factor for variable costs. PacifiCorp may also propose some share of new resources be allocated to either or both the "PacifiCorp – Subscription" bucket or "PacifiCorp – Reserves" bucket.

H. New Resources – Non-System Subscription

Q. PLEASE EXPLAIN THE TREATMENT OF NEW GENERATION THAT WILL NOT BE SHARED BY ALL CUSTOMERS AND TREATED AS NON-SYSTEM SUBSCRIPTION.

A. New generation that is not accepted by all six states will not be constructed unless it is fully subscribed to by one or more states or as PacifiCorp may otherwise propose (*e.g.*, PacifiCorp may propose that 80% of the new resource be subscribed to by one or more states and 20% be used by PacifiCorp to serve large loads or to provide reserves). The states participating in a subscribed new resource will determine whether that subscription will be based on fixed shares or dynamically allocated shares and, if dynamically allocated, the methodology used to calculate the shares over time. Each such resource will have its own unique allocation factor as a result (*e.g.*, SG-4.X). Table 9 of Exhibit JKL-1 includes an example of this process. This process will eventually lead to the development of generation portfolios unique to each state that are tailored to their states' needs and energy

policies. It will also provide some protection to the Company from allocation risk.

I. Qualifying Facilities (QFs)

Q. PLEASE EXPLAIN THE TREATMENT OF QFs.

A. The cost allocation of QF contracts will follow the method described in the 2020 Protocol with all legally enforceable obligations under a QF agreement before December 31, 2019, system assigned using an SG-5 allocator. Other than the Washington treatment, no state has objected to the system treatment for these contracts, but if a commission disallowance occurs, the costs could be made the responsibility of the approving state, or the Company, and a sub-factor adjustment could be made to reassign the cost responsibility (*e.g.*, SG-5.1). This methodology assumes Washington is treated the same as the other five states such that any difference in cost allocation between the Washington 2026 Protocol and the Allocation Framework would be the Company's responsibility. Any post-2019 QF contracts will be situs assigned and will have a QF-5.X allocation factor that would designate situs assignment for each new contract (X denoting the new contract; QF-5.1, QF-5.2, etc.).

J. Transmission Cost Allocations

Q. WHAT IS THE PRIMARY DRIVER OF COST CAUSATION FOR TRANSMISSION?

A. Transmission infrastructure (lines, substations, etc.) is mostly fixed-cost plant built to handle the system's highest demand periods reliably, not the total volume of energy flowing over all hours. It is the size of the "pipe" and not the volume flowing through it. Capacity must be there consistently whether it is used 5% of the time or 95% of the time. Costs get allocated based on how much a state/customer contributes to those peaks,

ensuring fairness and matching who drives the need for capacity. An additional factor for consideration is the consistency between the cost allocation and transmission planning. The Federal Energy Regulatory Commission ("FERC") Order 888 states:

> We are reaffirming the use of a twelve monthly coincident peak (12 CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks.[62]

Q. HOW DOES PACIFICORP CHARGE TRANSMISSION (WHOLESALE) CUSTOMERS?

A. PacifiCorp stated:

> The Federal Energy Regulatory Commission (FERC) transmission formula rate uses a 12 CP for allocating transmission costs to customers with network load service, which is the defined FERC methodology of using a load ratio share on a monthly basis (12 CP) and as a result PacifiCorp utilizes this method to charge customers and it is the method approved in the transmission formula rate.[63]

Q. WHAT DO YOU RECOMMEND IN THE ALLOCATION FRAMEWORK?

A. The Allocation Framework, as a general premise, would allocate transmission facilities and all future transmission shared by the states as bulk transmission and would be allocated using a 12 CP transmission allocator. The 12 CP method more closely aligns with cost causation and with planning as stated above. The use of a 12 CP method captures the highest demand hour each month across the year and is averaged to smooth out seasonal swings or investment cycles. In a Brattle Group report, Brattle concluded that:

> Energy allocators are used often in retail rates for small customers, including for the allocation of fuel and other variable costs that are tied to the volume of energy consumed, but they are not utilized as often in the cost allocation of transmission infrastructure in the U.S.[64]

---

[62] *Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,665 (1996).
[63] Response to UTLCG Data Request 2.44, subpart j (provided in Exhibit JKL-5).
[64] The Brattle Group, *Transmission Cost Allocations Among AEP-East Operating Companies* at 40 (2024).

The Allocation Framework proposal of using a 12 CP method based on 100% demand with no weighting for energy is stable and predictable for rate making purposes and will send the proper price signals. Finally, a 12 CP method will allocate fewer costs to states that have a lower annual capacity factor – *i.e.*, whose peak loads change relatively more over the course of the year – than an allocator based on, for example, fewer CPs looking only at summer or winter peak months. A 12 CP method can accomplish this without having to rely on an energy component in the allocator.

Q. WHAT ARE THE IMPACTS OF EXCLUDING THE ENERGY COMPONENT IN THE SYSTEM TRANSMISSION ("ST") FACTOR?

A. Initially, it results in a very small, approximately $0.7 million, increased transmission revenue requirement to Utah as shown in Table JKL-6. Status quo refers to a 75% demand (12 CP) and 25% energy weighting. However, if additional large, high-load factor customers come into Utah, this methodology would be to Utah's collective benefit.

Table JKL-9
Utah Impact of Change to ST Allocator

	Transmission Revenue Requirement ($ 000s)		
	Transmission		
	Status Quo	12CP	Difference
UTAH			
Total Jurisdiction	494,376	495,050	674

K. Net Power Costs and Capacity Leaning

Q. WHAT IS THE PROBLEM WITH CAPACITY LEANING?

A. As states move to increasingly unique resource portfolios, it may become the case that states holding more intermittent resources rely on or lean on states holding more dispatchable resources in both the short- and long-term.

Q. WHAT IS THE SHORT-TERM ISSUE ASSOCIATED WITH CAPACITY LEANING?

A. In the short term, for example in a particular hour, day, or month, a state whose generation portfolio relies to a large extent on intermittent resources may find that there are hours when those resources are not generating as anticipated, causing that state to need electricity from other PacifiCorp resources or the market to meet load requirements. PacifiCorp holds operating reserves specifically to meet these short-term system balancing requirements.

Q. HOW DOES THE ALLOCATION FRAMEWORK HELP ADDRESS SHORT-TERM CAPACITY LEANING?

A. As outlined in the Allocation Framework method in Exhibit JKL-1 and addressed in the testimony of UTLCG witness Mullins, the Allocation Framework contemplates ultimately moving to a calculation using nodal pricing in conjunction with the EDAM. A nodal pricing system can help ensure that, whenever a resource is dispatched, the state(s) bearing the costs of that resource get the benefits associated with the electricity generated. However, more work needs to be done and more information is needed. Customers have paid for the development of a nodal pricing model but have yet to see it implemented. Until more information is obtained (including potentially from EDAM), the Company should file any rate case using the 2020 Protocol methodology. This is further discussed by UTLCG witness Mullins.

Q. DOES THE NODAL PRICING MODEL OR THE EDAM ADDRESS LONG-TERM ISSUES?

A. Unfortunately not. The nodal pricing model and/or the EDAM will provide essentially energy-based "revenues" to states that pay the fixed and variable costs for resources that

are capable of meeting short-term needs like gas peaking units. But if a state does not pay for sufficient capacity to meet long-term planning reserve requirements, that is another issue entirely.

Q. HOW DOES PACIFICORP PROVIDE FOR PLANNING RESERVES TODAY?

A. Today planning reserves are reflected in the Company's six-state IRP. That plan provides for sufficient generation both to meet expected needs over the long-term and a planning reserve margin as a safety net in case there is unexpected load growth or unexpected generation shortfalls due to, for example, forced outages. In a world where everyone paid for a fixed slice of all of the generation, everyone essentially paid equally for capacity acquired to provide a planning reserve margin.

Q. WHAT IS THE ISSUE GOING FORWARD?

A. Going forward, each state will have a separate responsibility to ensure that the combination of situs and shared resources provides a sufficient planning reserve margin to adequately serve customers in that state, with no capacity leaning as described previously. But there is no mechanism currently existing for one state to force another state to acquire additional reserves. And, further, there is no requirement from FERC or other regional entity requiring that each specific PacifiCorp state maintain a particular planning reserve level into the future.

Q. DOES THE ALLOCATION FRAMEWORK PROVIDE A SOLUTION TO THE ISSUE OF LONG-TERM CAPACITY LEANING AND THE RISK IF STATES ELECT TO MAINTAIN DIFFERENT PLANNING RESERVE MARGINS?

A. No, not at this time. This is an issue that will require additional thought and work and will greatly depend on whether and how PacifiCorp chooses to participate in regional capacity

sharing programs or regional markets that have more specific long-term capacity reserve requirements. UTLCG witness Mullins provides further explanation on the current challenges with capacity leaning with the absence of PacifiCorp's participation in the Western Resource Adequacy Program ("WRAP").

IX. RECOMMENDATION

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH RESPECT TO THE 2026 PROTOCOL AND YOUR PROPOSED ALLOCATION FRAMEWORK?

A. I recommend that the Commission reject the 2026 Protocol, stay this case or open an investigation, and order the Company to participate in joint discussions with parties in the state, and to the extent possible, collaborate with the other Five States, to present to the Commission a solution with a defined deadline for a report (*e.g.*, August 31, 2026).

Furthermore, I recommend the use of the Allocation Framework as a starting point for the development of a new methodology to address the diverging portfolios that will inevitably occur with the Oregon exit from coal and all states preferring different energy portfolios. I acknowledge there are remaining issues to be addressed, such as the capacity leaning issue, but the Allocation Framework provides a useful starting point, with an explicit identification of the generation assets that are explicitly the Company's responsibility and available for use by other states or large customers. Importantly, this approach does not result in an increase in costs to customers as a consequence of a change in allocation methodology, whether through a deferral or included in an upcoming case.

While parties collaborate on a cost allocation approach, the Commission should order that any rate case filed prior to approval of a new allocation methodology be filed

with an analysis based on the 2020 Protocol. This ensures parties and the Commission have information necessary to evaluate any proposals presented.

Additionally, I have identified areas related to accounting, reporting and audit trails, and the handling of accumulated depreciation that should be considered by the Commission.

In short, it is in the public interest to reject the 2026 Protocol and establish an ordered process to further develop the Allocation Framework. Indeed, that would give a pathway to a permanent solution to generation allocations and multiple portfolios for subsequent approval by the Commission.

X. SUMMARY AND CONCLUSION

Q. DO YOU HAVE ANY FINAL COMMENTS?

A. Yes. It is unfortunate that the Company finds itself in the situation it is in. The Company could have first approached the Five States to determine if they were willing to give up their 92.5% of Chehalis *before* the Company committed to Washington almost 500 MWs of generation that is currently included in the other Five States' rate base. Were the states given that opportunity[65] and chose to maintain their Chehalis share before the Washington proposal, the Company could have pursued alternative generation for Washington, whether it was through purchase contracts or asset acquisitions such as batteries included in the Integrated Resource Plan. Instead, the Company chose to mitigate its 2026 CCA cost risk

[65] For instance, while I am not a lawyer, in my opinion it seems the Company could have followed the Commission's Rule R746-401-3. Section (B) states: Each public utility shall file with the Commission, at least 30 days before its being consummated, a report of the sale, transfer or other disposition by that utility of utility assets having a book cost allocated to Utah in excess of the lesser of ten million dollars or five percent of gross investment in utility plant devoted to Utah service at the latest balance sheet date as set forth in its most recent annual report on file with the Commission. (Emphasis added).

of $54.9 million while claiming an allocation shortfall of $49.3 million[66] (potentially a surplus for 2022-2024) owed by the Five States. Put differently, the Company's approach to multistate cost allocation appears motivated by (1) eliminating the Commission's disallowance of CCA costs and (2) covering *Washington's* allocation shortfall. All this at an increased cost to the Five States and a decreased cost to Washington. This is not just, reasonable, or in the public interest.

However, the Company now finds itself in a situation where a resource will potentially be double-counted (192.5%). If the Commission follows the UTLCG Allocation Framework, the unallocated generation of 522 MWs gets transparently set aside for use to meet future native load or large load requests that would be based on evidence and cost effectiveness brought before the Commission. If that happens, the Company will have a new revenue stream to cover the unallocated generation. But that would leave the system 500+ MW short to then serve Washington and, again, the Company would either need to build or buy generation for Washington, *as should be the case*. If the Company physically needs the coal and east-side gas to serve Washington because it chose to not build or buy generation, then there will be no physical generation to be subscribed to by states or large load, and the generation assets may become financially impaired unless the overcollection of 192.5% of Chehalis covers enough of the cost to carry the assets on the books.

The Company has created its own "Sophie's Choice" and should deal with the consequences, not the customers of a state that has participated in and made concessions

[66] As discussed above, the Company's claim of an allocation shortfall is suspect at best. *See* discussion *supra* pp. 17-19, 25-26.

to the multi-state process for decades. The 2026 Protocol should be given no further consideration.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.