BEFORE THE UTAH PUBLIC SERVICE COMMISSION

Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations	DOCKET NO. 24-035-04

DIRECT TESTIMONY

AND EXHIBITS

OF

KEVIN C. HIGGINS

On Behalf of

Utah Association of Energy Users

October 17, 2024

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevin C. Higgins. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

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

A. I am a Principal in the firm of Energy Strategies, LLC, a private consulting firm that specializes in economic and policy analysis applicable to energy production, transportation, and consumption.

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

A. My testimony is being sponsored by the Utah Association of Energy Users ("UAE").

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE UTAH PUBLIC SERVICE COMMISSION ("PSC" OR "THE COMMISSION")?

A. Yes. Since 1984, I have testified in 49 dockets before the Commission on electricity and natural gas matters.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE ANY OTHER STATE UTILITY REGULATORY COMMISSIONS?

A. In addition to these Utah proceedings, I have testified in approximately 255 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Colorado, Florida, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, North Carolina, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings before the Federal Energy Regulatory Commission and prepared expert reports in state and federal court proceedings involving utility matters.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the appropriate RMP revenue requirement under the projected test period requested by the Company, which is the year ending December 31, 2025.

Q. PLEASE SUMMARIZE YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS CONCERNING REVENUE REQUIREMENT.

A. I offer the following conclusions and recommendations:

1) In discovery, RMP has identified $199.6 million in average test period gross plant (Total Company) that was included in the test period revenue requirement, but which now is not expected to be in service by December 31, 2025 or has been canceled. In my opinion, canceled plant should be excluded from the revenue requirement, as should post-2025 plant, as the latter falls outside the bounds of the projected test period. This adjustment reduces the Utah revenue requirement deficiency by **$14,273,432**.

2) The revenue requirement for the Gateway South transmission project should be adjusted so as to achieve a break-even result for customers using the Medium Gas/Medium CO_2 price-policy scenario with the $843 million credit associated with an alternative transmission project removed from the Company's economic analysis. This adjustment results in a disallowance of 32.9% of the cost of the project. This adjustment reduces the Utah revenue requirement deficiency by **$32,981,668**.

3) The Project Litespeed transmission project should be excluded from the Utah revenue requirement in this case because the Company has not demonstrated that it will be used and useful during the 2025 test period. This adjustment reduces the Utah revenue requirement deficiency by **$1,833,103**.

4) The rate base and O&M expense associated with the Fall Creek Hatchery should be excluded from Utah rates consistent with the requirements of the 2012 Settlement Stipulation approved by the Commission in Docket No. 11-035-200, which precludes the recovery of Klamath dam removal or removal-related costs from Utah customers. This adjustment reduces the Utah revenue requirement deficiency by **$2,495,883**.

5) Current Utah rates include the recovery of $3,340,339 in Klamath-related depreciation expense and $4,268,426 in Klamath-related relicensing and process costs, totaling $7,608,765 per year. These obligations were fully paid off at the end of 2022, but have continued to be recovered in rates throughout 2023 and 2024. In this case, RMP seeks recovery of Klamath-related capital additions as well as Klamath-related transmission investment. I recommend that the revenues that Utah customers have been paying for expired Klamath-related obligations since January 1, 2023 be used to offset the cost of the Klamath regulatory asset and permanently buy down the Klamath-related transmission investment. These adjustments reduce the Utah revenue requirement deficiency by **$630,034** and **$58,079** respectively.

6) RMP's proposal to recover the costs of severance expense and the termination of the Safe Harbor Lease associated with its retired Cholla Unit 4 plant should be rejected as these expenditures were not identified as being

eligible for deferral and later recovery in the Company's previous rate case, Docket No. 20-035-04. This adjustment reduces the Utah revenue requirement deficiency by **$432,376**.

7) For Jim Bridger Units 1 and 2, which have been converted from coal to gas, a four-year projection of generation overhaul costs as gas units should be substituted for the four years of historical costs as coal units. This adjustment reduces the Utah revenue requirement deficiency by **$412,847**.

8) The inflation escalator applied by RMP to its non-labor O&M expense should be removed. This adjustment reduces the Utah revenue requirement deficiency by **$71,333**.

9) The share of RMP's Annual Incentive Plan ("AIP") expense that is related to Company financial performance should be funded by shareholders, not customers. This adjustment reduces the Utah revenue requirement deficiency by **$433,857**.

10) I have corrected several non-net power cost errors acknowledged by RMP:

i. RMP used incorrect allocation factors to determine the Utah-allocated base period wildland fire operations & maintenance ("O&M") expenses recorded in FERC Accounts 560 and 580 incorporated in the Wildland Fire O&M adjustment. My correction of this error is not intended to address the substance of the Wildland Fire revenue requirement in this case, as I understand that subject has been consolidated with the Fire Plan Docket. Rather, it is intended to rectify an input error in RMP's proposed revenue requirement. Correcting this error *increases* the Utah revenue requirement deficiency by **$1,047,992**.

ii. Expenses associated with the wildland fire deferral recorded in FERC Account 590 were inadvertently included in the general rate case. As is the case with the preceding adjustment, my correction of this error is not intended to address the substance of the Wildland Fire revenue requirement in this case. Rather, it is intended to rectify what is essentially a clerical error in RMP's proposed revenue requirement. Removing these expenses from the base revenue requirement reduces the Utah revenue requirement deficiency by **$6,417,975.**

iii. The Electric Vehicle Infrastructure Program (EVIP) amortization expense was inadvertently included in the general rate case. Removing this expense reduces the Utah revenue requirement deficiency by **$2,191,266**.

iv. In addition to the errors itemized above, I include an update to the actual amount of the Deer Creek Recovery Royalties paid by the Company, in place of the estimate included in the revenue requirement. This adjustment reduces the Utah revenue requirement deficiency by **$107,717**.

11) In calculating the transmission revenue credit, RMP is not using the current FERC-approved rate for transmission service for the first five months of the 2025 test period. The Commission ordered RMP to use the current FERC-approved rate for this purpose. This adjustment reduces the Utah revenue requirement deficiency by **$6,033,309**.

12) Costs associated with the State of Washington's Climate Commitment Act, including the incremental cost of altering the Company's dispatch, should be disallowed from the Utah test period revenue requirement. The Climate Commitment Act should be viewed as a Washington state policy action that should not implicate Utah rates. This adjustment reduces the Utah revenue requirement deficiency by **$13,038,382**.

13) Correcting an error in the development of RMP's Official Forward Price Curve used in the projection of its test period net power costs results in a **$3,063,798** reduction to Utah revenue requirement deficiency.

Q. PLEASE SUMMARIZE THE IMPACT OF UAE'S ADJUSTMENTS TO RMP'S PROPOSED REVENUE INCREASE.

A. The impacts of UAE's recommended adjustments are summarized in Table KCH-1 below.

As shown in Table KCH-1, UAE's adjustments reduce RMP's Utah base revenue requirement deficiency by **$83,427,067** relative to RMP's filing. UAE's final base revenue requirement results in a **$196,316,559** increase relative to current base rates in Utah. This contrasts with the base rate increase of $279,743,626 proposed by RMP.[1]

Note that Table KCH-1 does *not* remove RMP's requested test period revenue requirement related to its Wildland Fire Fund, even though the revenue requirement for this item will be addressed in a consolidated docket. As I noted above, the only adjustments

[1] McCoy Exhibit RMP__(SEM-10A) - Rate Mitigation Calculations - Aug 28 Revised.

I made related to the Wildland Fire Fund revenue requirement were to correct for known errors in RMP's filing.

Table KCH-1 also does not show the non-base revenue recovery proposed by RMP in its filed case, namely $92,941,024 for a proposed Insurance Cost Adjustment ("ICA") mechanism and $21,028,285 for Schedule 97, Wildfire Mitigation Balancing Account, as the revenue requirements for these items will be addressed in other dockets consolidated with this case.

Table KCH-1
Summary of UAE Revenue Requirement Adjustments for 2025 Test Period

RMP Requested Base Revenue Requirement Increase	**$564,925,480**
RMP Rate Mitigation Reduction	**($285,181,854)**
RMP Requested Base Rate Increase	**$279,743,626**

Summary of Base Revenue Requirement Impact of UAE Adjustments

	Adjustment	Increase
Delayed/Canceled Capital Additions	**($14,273,432)**	**$265,470,194**
Gateway South	**($32,981,668)**	**$232,488,526**
Project Litespeed	**($1,833,103)**	**$230,655,424**
Fall Creek Hatchery	**($2,495,883)**	**$228,159,541**
Klamath Regulatory Asset	**($630,034)**	**$227,529,507**
Klamath Dam Removal Transmission Project	**($58,079)**	**$227,471,428**
Cholla 4 Severance & Safe Harbor Lease Costs	**($432,376)**	**$227,039,052**
Generation Overhaul	**($412,847)**	**$226,626,205**
Non-Labor O&M Inflation	**($71,333)**	**$226,554,871**
Annual Incentive Plan	**($433,857)**	**$226,121,014**
Wildland Fire O&M Correction to Accts. 560 & 580	**$1,047,992**	**$227,169,006**
Wildland Fire O&M Correction to Acct. 590	**($6,417,975)**	**$220,751,031**
EVIP Amortization Expense Correction	**($2,191,266)**	**$218,559,765**
Deer Creek Recovery Royalties Update to Actuals	**($107,717)**	**$218,452,048**
Transmission Revenues	**($6,033,309)**	**$212,418,740**
NPC – Washington CCA	**($13,038,382)**	**$199,380,357**
NPC – OFPC Correction	**($3,063,798)**	**$196,316,559**
Total UAE Adjustments	**($83,427,067)**	
Base Revenue Req. Increase reflecting UAE Adjustments		**$196,316,559**

II. ADJUSTMENT FOR PLANT NOT EXPECTED TO BE IN SERVICE DURING THE TEST PERIOD

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR PLANT NOT EXPECTED TO BE IN SERVICE DURING THE TEST PERIOD.

A. RMP is using a fully projected test period ending December 31, 2025, which is approximately 18 months beyond the Company's filing date of June 28, 2024. In its Application seeking approval of this future test period in this docket, RMP noted that "[t]o be just and reasonable for both customers and utilities, rates must accurately reflect prudent costs expected to be incurred by a utility during the period when rates are in effect."[2] RMP also justified its choice of a 2025 test period by stating that "if the 2025 Proposed Test Period is not approved, the rates in effect for the rate-effective period will not be aligned with the Company's expected costs of service which would deprive the Company of a fair opportunity to recover its costs."[3]

RMP's use of such a forward-reaching test period runs the risk of including the cost of facilities in the revenue requirement that will not be in service during the test period due to changes in the construction schedule. Indeed, that is what has occurred in this case. In responses to discovery, RMP identified 69 projects each valued at $1 million or greater and 16 smaller intangible plant projects each valued at less than $1 million that have been canceled or delayed beyond the December 31, 2025 test period.[4] Measured at the end of the test period, RMP identified a total of $421.5 million in projected gross plant additions

[2] Rocky Mountain Power's Notice of Intent to File a General Rate Case and Request for Approval of Test Period ("Test Period Application") at 5.
[3] *Id*. at 5.
[4] RMP responses to Data Requests OCS 11.5, Attachment OCS 11.5; and OCS 11.7, Attachment OCS 11.7, included in UAE Exhibit RR 1.18.

(Total Company) that have been canceled or delayed beyond the December 31, 2025 test period. Measured on an average test period basis, this corresponds to $199.6 million in gross plant (Total Company) that was included in the test period revenue requirement, but which now is not expected to be in service by December 31, 2025, or has been canceled. Canceled plant should be excluded from the revenue requirement, as it obviously has no nexus to the Company's expected cost of service, as should post-2025 plant, as the latter falls outside the bounds of the projected test period.

Q. WHAT IS YOUR RECOMMENDED ADJUSTMENT?

A. All post-2025 and canceled plant and associated depreciation expense should be removed from the 2025 revenue requirement. The resulting impact from this adjustment is a reduction of approximately **$14,273,432** to the Utah revenue requirement deficiency. I note that my adjustment does not include the impact of accumulated deferred income tax ("ADIT"), because RMP failed to provide the complete components of this adjustment in discovery.[5] This adjustment is shown in UAE Exhibit RR 1.1.

III. GATEWAY SOUTH TRANSMISSION PROJECT

Q. WHAT IS THE GATEWAY SOUTH TRANSMISSION PROJECT?

A. The Gateway South transmission project consists of a 416-mile 500 kV transmission line from the Aeolus substation in Wyoming to the Clover substation in Utah, along with associated facility rebuilds, substation expansions, and new compensation stations.[6] The

[5] RMP responses to Data Requests OCS 11.5 and 11.7, included in UAE Exhibit RR 1.18.
[6] Direct Testimony of Richard A. Vail, lines 260-273.

project is expected to be completed in December 2024 at a cost of $2.126 billion, of which $954 million is allocated to Utah.[7]

Q. WHAT BENEFITS ARE ANTICIPATED FROM THE GATEWAY SOUTH PROJECT?

A. According to RMP, the Gateway South project, in combination with the Gateway West Segment D.1 project, will allow the Company to interconnect approximately 2,030 MW of new Wyoming resources, 1,640 MW of which are wind resources selected in the Company's 2020 all-source RFP. The transmission projects are also expected to improve reliability of the transmission system by providing capacity between Gateway West and Gateway Central, to relieve transmission congestion on the existing Wyoming 230 kV transmission system, and to improve load serving capability in Utah.[8]

Q. HAS RMP PRESENTED AN ANALYSIS OF THE NET BENEFITS ASSOCIATED WITH THE PROJECT?

A. Yes. The results of this analysis are presented in the Direct Testimony of RMP witness Mr. Rick Link.

Q. WHAT DO THE RESULTS OF THE COMPANY'S ANAYSIS SHOW?

A. As shown in Mr. Link's Exhibit RTL-1, the Company estimates that the combined Gateway South and Gateway West Segment D.1 transmission projects will produce a present value of revenue requirement ("PVRR") net benefit of $260 million over 20 years, inclusive of $132 million of risk-adjusted benefits, using the Company's Medium Gas/Medium CO_2 price-policy scenario. This price-policy scenario assumes a levelized Henry Hub natural

[7] *Id.*, p. 13, Table 1.
[8] *Id.*, lines 285-310.

gas price of $4.44 MM/Btu from 2025-2040 and effective CO_2 pricing of $9.93/ton in 2025 rising to $57.94/ton in 2040.[9] The gas price assumptions are drawn from the Company's Official Forward Price Curve dated March 31, 2021, which represented the most recent forward curves available when the Company prepared the inputs for its 2021 IRP.[10]

Q. DOES RMP IDENTIFY NET COST/BENEFIT RESULTS USING OTHER PRICE-POLICY SCENARIOS?

A. Yes. Under the Medium Gas/No CO_2 price-policy scenario, the projects result in net *costs* to customers of $289 million (including $104 million of risk-adjusted benefits) and under the Low Gas/No CO_2 price-policy scenario, the projects result in net *costs* to customers of $670 million (including $85 million of risk-adjusted benefits). RMP also presents a High Gas/High CO_2 price-policy scenario, in which the projects result in net benefits to customers of $1.1 billion (including $168 million of risk-adjusted benefits) and a Social Cost of Greenhouse Gas scenario, in which the projects result in net benefits to customers of $2.819 billion (including $251 million of risk-adjusted benefits).

Q. OF THE PRICE-POLICY SCENARIOS PRESENTED, WHICH DOES THE COMPANY APPEAR TO RELY UPON MOST IN JUSTIFYING ITS INVESTMENT IN THE GATEWAY SOUTH TRANSMISSION PROJECT?

A. The Company appears to rely most heavily on the results of the Medium Gas/Medium CO_2 price-policy scenario. As Mr. Link notes, the medium gas price assumptions are aligned with the Company's forward price curves at the time it developed its 2021 IRP. Even more

[9] *See* Direct Testimony of Rick T. Link, lines 354-364, including Table 2.
[10] *See id.*, lines 365-369.

noteworthy, the "no CO_2" assumptions produce negative net results for customers, and therefore do not provide economic support for the project.

Q. DO YOU HAVE ANY CONCERNS REGARDING THE NET BENEFITS ANALYSIS PRESENTED BY THE COMPANY?

A. Yes. I will not address the efficacy of each component in the Company's calculation. However, a single major element in the Company's calculation of net benefits stands out as warranting significant concern. This element consists of a credit against the cost of the Gateway South transmission project in the amount of $843 million on a 20-year net present value basis. This credit appears in each of the five price-policy scenarios presented by RMP.

Q. PLEASE EXPLAIN THE NATURE OF THE $843 MILLION CREDIT IN THE COMPANY'S CALCULATION.

A. The credit is intended to represent the cost, on a net present value basis, of an alternative transmission project that the Company contends it would have been required to build to fulfill a transmission service request from a single large transmission customer in the absence of Gateway South. The hypothetical alternative transmission project consists of a 235 kV line costing $1.4 billion. According to the logic of RMP's contention, since the Company would have been obligated to build the alternative transmission project to serve this single customer anyway, only the incremental costs above the cost of this alternative are attributable to the Gateway South project for the purpose of calculating net benefits to retail customers. In effect, this assumption reduces the cost of the Gateway South transmission project from $1.261 billion (on a 20-year net present value basis) to just $418 million (on a 20-year net present value basis). This assumption represents a reduction of

67% for the purpose of the net benefit calculation. Significantly, the 20-year net benefit of \$260 million calculated by the Company for the combined Gateway South and Gateway West Segment D.1 transmission projects using Medium Gas/Medium CO_2 price-policy scenario relies on this effective 67% reduction in the project's cost. Absent this assumed reduction in the effective cost of the Gateway South transmission project, the Medium Gas/Medium CO_2 price-policy scenario would not show a net benefit to customers from the combined Gateway projects, but rather a net *cost* of \$415 million (\$260 million - \$843 million + \$169 million).[11] Within the framework of the Company's analysis, the economic justification of the Gateway South project hinges on the reasonableness of the assumption that, absent Gateway South, the Company would have been obligated to build an alternative transmission line largely at retail ratepayer expense to serve the request of a single third-party transmission customer.

Q. IS THIS A REASONABLE ASSUMPTION?

A. No. This assumption is not reasonable for two important reasons. First, if we assume that the third party transmission customer requested service from the Company in a manner that would have obligated the Company to build a new line to serve that request, *i.e.*, if this single customer would have *caused* the new line to be built, then in accordance with FERC Order 890, the \$1.4 billion incremental cost of that facility could have been charged to that customer in the form of a monthly incremental cost transmission rate in lieu of the monthly embedded cost rate. Of course, faced with such a price tag, the prospective customer might have been dissuaded from pursuing the request any further. But in either case, whether the

[11] If the \$843 million avoided transmission credit is eliminated, the assumptions used in RMP's analysis would result in an increase in the Transmission OATT Credit of \$169 million (20% x \$843 million) in Mr. Link's Exhibit RTL-1.

third-party customer agreed to pay the incremental cost or declined to pursue the project any further, a net present value cost of $843 million paid primarily by the Company's retail customers would not occur. It is simply not reasonable or realistic to assume that absent Gateway South, PacifiCorp retail customers would have been obligated to pay 80% of the cost of a $1.4 billion transmission line constructed to serve a single third-party transmission customer.[12] Consequently, it is equally unreasonable and unrealistic to apply an $843 million credit against the cost of the Gateway South project when calculating the net benefits to customers of that investment. Instead, when measuring the net benefits of the Gateway South project, the total cost of the project should be taken into account. The analysis should not assume that 67% of the project comes free of charge.

Q. YOU REFERRED TO FERC ORDER 890. PLEASE ELABORATE ON THE RELEVANCE OF FERC ORDER 890 TO THIS DISCUSSION.

A. FERC Order 890 was issued February 16, 2007. Broadly speaking, it amended the regulations and the pro forma open access transmission tariff adopted in Order Nos. 888 and 889. Among many other things, Order 888 articulated FERC's "higher of" Pricing Policy. The "higher of" Pricing Policy states that system expansions should be priced at the higher of the embedded cost rate (including the expansion costs) or the incremental cost rate, consistent with the Transmission Pricing Policy Statement issued by FERC on October 26, 1994.[13] FERC Order 890 reaffirmed and clarified the "higher of" pricing

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[12] In the Company's analysis, its retail customers are assumed to pay 80% of the incremental revenue requirement of the alternative transmission line and FERC-jurisdictional customers are assumed to pay the other 20%. *See* RMP Response to Data Request UAE 6.7(c), included in UAE Exhibit RR 1.18.

[13] *See Preventing Undue Discrimination and Preference in Transmission Service*, (FERC Order 890), 72 FR 12266-01, ¶ 870 n.533 (Mar. 15, 2007) ("In Order No. 888, the Commission stated that system expansions should be priced at the higher of the embedded cost rate (including the expansion costs) or the incremental cost rate, consistent with the Transmission Pricing Policy Statement."); *Inquiry Concerning the Commission's Pricing Policy for Transmission*

policy with respect to the calculation of a monthly incremental cost transmission rate for system expansions.[14] When asked in discovery why RMP did not assume in its analysis that the third-party customer could have been required to pay the "higher of" transmission rate, the Company objected and did not provide an explanation.[15]

Q. YOU STATED THERE ARE TWO REASONS WHY THE COMPANY'S ASSUMPTION IS NOT REASONABLE. WHAT IS THE SECOND REASON?

A. As a factual matter, the third-party transmission customer requested service *after* the Company indicated that it intended to construct the Gateway South project. The customer's interconnection request was filed on May 7, 2021 and its transmission service request was filed on March 15, 2019. On the date the customer filed its transmission service request, Gateway South was already included in the Company's long-term transmission plan and it was identified on the Company's OASIS as a planned project.[16] This sequence of events calls into question the premise that the service request of the third-party transmission customer would have caused a system expansion. If this customer was merely seeking service on a line the Company was already committed to build, there is no basis for assuming an $843 million credit for "avoided transmission" in the net benefit calculation. Since the Company had already announced it was going to build Gateway South prior to receiving the third-party customer's service request, then the proper net

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Services Provided by Public Utilities Under the Federal Power Act (Transmission Pricing Policy Statement), 59 FR 55031 at 55032 (Nov. 3, 1994) ("In order to provide new or expanded transmission service, a utility may be required to add expensive transmission assets, which can result in an increase in rolled-in embedded cost rates. To address this possibility, the Commission has allowed a utility to charge transmission-only customers the higher of embedded costs (for the system as expanded) or incremental expansion costs, but not the sum of the two.").

[14] FERC Order 890 at ¶¶ 870-885.

[15] RMP Responses to Data Request UAE 6.7(d) and 6.7(e), included in UAE Exhibit RR. 1.18.

[16] RMP Response to Data Request UAE 14.1, included in in UAE Exhibit RR 1.18.

benefit analysis should include the full cost of the line without an offsetting credit for the cost of an alternative line.

Q. HAS UAE RAISED CONCERNS ABOUT THE NET BENEFITS OF THE GATEWAY SOUTH PROJECT PRIOR TO THIS GENERAL RATE CASE?

A. Yes. In testimony filed in the Gateway South CPCN case, Docket No. 21-035-54,[17] UAE witness Justin Bieber disagreed with the Company's modeling assumption of "unavoidable transmission costs" to provide service to this same third-party transmission customer. Just as I am noting in this case, Mr. Bieber pointed out that according to FERC's transmission pricing policy, a utility can charge the "Higher of" its FERC approved OATT rate for transmission service that reflects embedded cost, or an incremental cost rate that is designed to recover the cost to provide service. Mr. Bieber explained that if the Company's FERC approved OATT rate is not sufficient to recover the annual revenue requirement associated with network upgrades required to provide transmission service to a third party, then it has the ability to charge an incremental rate that is designed to recover that entire revenue requirement and hold the Company's retail customers harmless.[18]

While UAE did not oppose RMP's request for a CPCN to construct Gateway South, UAE recommended that if the Commission were to approve RMP's request to grant a CPCN to build Gateway South, the Commission should clarify in its Order that the granting of a CPCN does not constitute a project pre-approval or a judgment regarding the prudency or future recovery of costs associated with the transmission line.

[17] *Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity for the Gateway South Transmission Project*, Docket No. 21-035-54.
[18] *See id.*, Direct Testimony of Justin Bieber, lines 85-95.

Q. WAS THE GATEWAY SOUTH CPCN GRANTED BY THE COMMISSION?

A. Yes. The Commission approved a settlement agreement, supported by UAE, that recommended approval of the CPCN, but with the following condition:

> The Parties agree that the approval of the CPCN is limited to a determination of the public convenience and necessity of the Project and that prudence, cost allocation, and rate recovery are not within the scope of the application. Prudence, cost allocation, and rate recovery will be addressed through a future regulatory process at the appropriate time.[19]

Consistent with this provision, in approving the settlement agreement, the Commission expressly stated:

> (3) Per the Settlement, this Order makes no determination as to the Project's prudence, RMP's recovery of the Project's costs, allocation of such costs, or any other issue preserved in the Settlement for future adjudication.[20]

Q. DID UAE RAISE ANY CONCERNS ABOUT THE ECONOMICS OF THE GATEWAY SOUTH PROJECT AS PART OF THE IRP PROCESS?

A. Yes. In February 2020, UAE filed comments raising concerns about the Company's inclusion of the Gateway South project in the preferred portfolio as part of the 2019 IRP. In particular, UAE noted the Company's failure to provide a robust economic analysis of potential transmission alternatives to Gateway South. Ultimately, the Commission declined to acknowledge the Company's Action Plan submitted with the 2019 IRP because of two deficiencies in the analysis placing Gateway South in the Action Plan. Specifically, the Commission was concerned that the Company did not model the Preferred Portfolio without Gateway South and that the Company excluded from its modeling the potential alternative evaluated in the Northern Tier Transmission Group 2018-2019 Regional

[19] *See* Docket No. 21-035-54, Settlement Stipulation (Feb. 22, 2022) at ¶ 12.
[20] *See* Docket No. 21-035-54, Order (Apr. 8, 2022) at 4.

Transmission Plan.[21] The Commission reiterated this concern when approving the 2020AS RFP.[22]

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE RECOVERY OF COSTS ASSOCIATED WITH THE GATEWAY SOUTH TRANSMISSION PROJECT?

A. I recommend that a portion of the revenue requirement attributable to the Gateway South transmission project be disallowed in this proceeding. As I discussed above, RMP's calculation of net benefits from this project relies heavily on the assumption that, absent the Gateway South project, the Company would have been obligated to construct a $1.4 billion alternative transmission project to meet the service request of large, third-party customer, and that 80% of the cost of this alternative project would have been recoverable from the Company's retail ratepayers. This assumption is simply not credible. If this assumption is eliminated from the analysis, the combined Gateway projects result in a net cost to customers of $415 million using the Medium Gas/Medium CO_2 price-policy scenario. My recommended adjustment is to reduce the revenue requirement attributable to the Gateway South transmission project to achieve a break-even result for customers using the Medium Gas/Medium CO_2 price-policy scenario with the $843 million credit removed from the analysis. This adjustment results in a disallowance of 32.9% of the cost of the project.

[21] *PacifiCorp's 2019 Integrated Resource Plan*, Docket No. 19-035-02, Order (May 13, 2020), pp. 21-22.
[22] Application of Rocky Mountain Power for Approval of Solicitation Process for 2020 All Source Request for Proposals, Docket No. 20-035-05, Order Approving 2020 All Source RFP (July 17, 2020), pp. 14-15.

Q. HOW DID YOU CALCULATE THE 32.9% DISALLOWANCE?

A. The calculation of my recommended disallowance is presented in UAE Exhibit RR 1.2. It is based on the relationship between the present value of revenue requirements for the Gateway South project, the Company's calculation of net benefits using the Medium Gas/Medium CO_2 price-policy scenario, and the Company's assumed "avoided transmission" credit. As I stated above, if the avoided transmission credit is eliminated from the analysis, the combined Gateway projects result in a net cost to customers of $415 million using the Medium Gas/Medium CO_2 price-policy scenario – even after accounting for risk-adjusted benefits calculated by the Company. Reducing the net cost to customers to zero (*i.e.*, break-even) would require a reduction in the present value of revenue requirements for the Gateway South project in this same amount, which is 32.9% of the $1.261 billion Gateway South present value of revenue requirements.[23]

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR GATEWAY SOUTH ADJUSTMENT?

A. The resulting impact from my Gateway South adjustment is a reduction of **$32,981,668** to the Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.2.

[23] $415 million/1.261 billion = 32.9%

Q. IF THE COMMISSION ADOPTS YOUR RECOMMENDED DISALLOWANCE, SHOULD ANY BENEFITS TO UTAH CUSTOMERS FROM THE GATEWAY SOUTH PROJECT BE REDUCED?

A. No. My adjustment reduces the recovery of Gateway South costs to match the benefits to customers. If benefits facilitated by the Gateway South project, such as production tax credits from wind resources that utilize Gateway South transmission facilities, are not passed on to Utah customers, then the Gateway South disallowance would have to be increased to match the reduction in benefits.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE MAGNITUDE OF YOUR RECOMMENDED DISALLOWANCE?

A. Yes. I recognize that my recommended disallowance is substantial, and I do not propose it lightly. My recommendation derives from a straightforward assessment of the Company's own economic analysis. If the Commission determines that there are long-term benefits to Utah customers from Gateway South that are not captured in that analysis, then the Commission may want to consider a multi-year phase-in of additional cost recovery. But for the purposes of this case, Gateway South cost recovery above what I am recommending does not appear to be justified by the economic analysis.

IV. <u>PROJECT LITESPEED TRANSMISSION PROJECT</u>

Q. WHAT IS THE PROJECT LITESPEED TRANSMISSION PROJECT?

A. RMP describes Project Litespeed as a customer-driven major load addition of 242 MW near Boardman, Oregon, which is in Pacific Power territory. However, there are no suitable facilities at or near the Project Litespeed site to serve the partial or full amount of load requested. But, RMP explains, this load can be served by facilities owned by Portland General Electric ("PGE") if PGE's facilities are upgraded. RMP maintains that the most efficient path forward is to enter into a line and load agreement with PGE, construct the initial service plan, and submit a transmission service request with BPA and PGE to meet project deadlines. RMP's filing includes a fairly detailed description of the investments needed to carry out this project.[24]

In the 2025 test period, the Company proposes to include $149.3 million (total Company) in plant-in-service for Project Litespeed,[25] most of which comes in at the end of the test period. According to RMP's response to discovery, initial commercial operation is not expected to commence until December 30, 2025, via a radial 500 kV interconnection between PGE's Grassland substation and the Company's new Apex substation, serving the Company's new Litespeed 230 to 34.5 kV substation. Full project completion is expected on December 15, 2027 following completion of the Maverick substation and Maverick to Apex 500 kV line.[26]

Q. DO YOU HAVE ANY CONCERNS ABOUT INCLUDING PROJECT LITESPEED IN THE UTAH REVENUE REQUIREMENT IN THIS CASE?

A. Yes. The Company indicates that the customer for which this investment is being made is not expected to take service until February 2026.[27] The 2026 start date of the customer's initiation of service, in combination with the projected December 30, 2025 initial commercial operations date for much of the test period investment calls into question the

[24] *See* Exhibit RMP___(SEM-3), pages 8.5.39 – 8.5.41.
[25] *See id*. page 8.5.27.
[26] RMP Response to Data Request UAE 13.1(b), included in UAE Exhibit RR 1.18.
[27] *See* Exhibit RMP___(SEM-3), page 8.5.39.

used and usefulness of this investment during the 2025 test period. I note that despite its location in Oregon, Project Litespeed was not included in the Company's requested rate base in Oregon in its most recent general rate case in that state, even though that case was also filed using a 2025 test period. RMP explained that Project Litespeed was excluded from its Oregon filing because it was not expected to come into service before the rate effective period in that jurisdiction, making it ineligible for inclusion in Oregon rates at this time.[28]

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION CONCERNING PROJECT LITESPEED?

A. I recommend that Project Litespeed be excluded from the Utah revenue requirement in this case due to the Company's failure to demonstrate that it will be used and useful during the 2025 test period.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR PROJECT LITESPEED ADJUSTMENT?

A. The resulting impact from my Project Litespeed adjustment is a reduction of **$1,833,103** to the Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.3.

[28] RMP Response to Data Request UAE 13.1(a), included in UAE Exhibit RR 1.18.

V. FALL CREEK HATCHERY

Q. WHAT IS THE FALL CREEK HATCHERY?

A. According to RMP's filing, the Fall Creek Hatchery was constructed to meet the Company's obligations under the Klamath Hydroelectric Settlement Agreement ("KHSA") signed on February 18, 2010, and amended on April 6, 2016, and November 30, 2016.[29] For years PacifiCorp has owned a different hatchery, the Iron Gate Hatchery, which is operated by the California Department of Fish and Wildlife. The Iron Gate Dam provides supply water to the Iron Gate Hatchery through the powerhouse intake structure. With the planned removal of the Lower Klamath Project dams, there will no longer be water supply for Iron Gate Hatchery from Iron Gate reservoir, and fish collection facilities at the base of Iron Gate Dam will be removed. In accordance with the KHSA, PacifiCorp is obligated to provide continued hatchery production for eight years after the removal of Iron Gate Dam.[30] The Fall Creek Hatchery was constructed to fulfill this obligation. RMP proposes to include this project in rate base as Hydroelectric Plant, with an in-service date of March 2024 and a total plant in service of \$36.5 million,[31] \$16.4 million of which is allocated to Utah.

[29] *See* KHSA, attached as UAE Exhibit RR 1.20.
[30] *See* Exhibit RMP___(SEM-3), page 8.5.35.
[31] *See id.,* page 8.5.25.

Q. ARE YOU FAMILIAR WITH THE KHSA AND THE HISTORY OF THE RECOVERY OF KLAMATH-RELATED COSTS IN UTAH?

A. Yes. I was a witness in the Company's 2012 general rate case, Docket No. 11-035-200,[32] which established a number of important parameters governing the recovery of Klamath-related costs from Utah customers. These parameters were laid out in paragraphs 58-60 of a Settlement Stipulation ("2012 Settlement Stipulation") approved by the Commission in that case. Among the provisions accepted by the Company in that Settlement Stipulation is that RMP may not recover from Utah ratepayers in this or any other proceeding any dam removal or removal-related costs associated with the KHSA. I am not an attorney, but the 2012 Settlement Stipulation and the KHSA make it clear that the construction of the Fall Creek Hatchery is a dam removal cost under the terms of those agreements, which is not recoverable from Utah ratepayers under the terms of the 2012 Settlement Stipulation.

Q. WHAT LANGUAGE IN THE 2012 SETTLEMENT STIPULATION GOVERNS THIS ISSUE?

A. Paragraph 60 addresses the issue of cost recovery. The treatment of cost recovery in this paragraph is so comprehensively and forcefully stated it is useful to restate it here in its entirety.

> 60. Notwithstanding the preceding paragraphs 58 and 59, the Company agrees that it may not recover from Utah ratepayers in this or any other proceeding any dam removal or removal related costs associated with the Klamath Hydroelectric Settlement Agreement ("KHSA"), including but not limited to "Facilities Removal", the "Secretarial Determination", the "State Cost Cap", or the implementation of the "Definite Plan" or "Detailed Plan" related to the Klamath Hydroelectric Project, and whether funded or incurred by a "Party" or "Parties", "States", or the "Dam Removal Entity,"

[32] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 11-035-200.

> as these terms are defined and used in the KHSA. The Company's agreement includes, without limitation, no recovery from Utah ratepayers of any dam removal or removal related cost resulting from any amendment to or substitute agreement for the KHSA, or dispute resolution, alternate or substitute funding, financing mechanism substitution, or shortfall funding described by the KHSA. Nothing in this paragraph shall preclude the Company from applying for recovery from Utah ratepayers of Utah's allocated share of costs that are prudently incurred by the Company in connection with: (i) "Decommissioning", as defined in the KHSA, and (ii) operation and maintenance of the Klamath Project for continued generation. Nothing in this paragraph, paragraphs 58 or 59, or in this Stipulation shall (i) preclude the Company from applying for recovery from Utah ratepayers of Utah's allocated share of costs that are prudently incurred by the Company in connection with potential future proceedings before the Federal Energy Regulatory Commission to relicense or decommission and/or remove the Klamath Project facilities, or (ii) be construed as approval or disapproval of any such future Company application for recovery from Utah ratepayers of costs identified in the immediately preceding sentence, nor as a waiver, compromise or limit of any party's rights, defenses, remedies, duties, or jurisdictional objections available under Federal or Utah law in connection with any such application.[33]

The very first sentence in this paragraph states that the Company agrees that it may not recover from Utah ratepayers, in this or any other proceeding, any dam removal or *removal-related* costs associated with the KHSA, including but not limited to "Facilities Removal" costs. The KHSA defines "Facilities Removal" as:

> [P]hysical removal of all or part of each of the Facilities to achieve at a minimum a free-flowing condition and volitional fish passage, site remediation and restoration, including previously inundated lands, measures to avoid or minimize adverse downstream impacts, and all associated permitting for such actions.[34]

Clearly the meaning of "Facilities Removal" in the KHSA goes well beyond the physical removal of the dams to include site remediation and restoration, as well as measures to

[33] 2012 Settlement Stipulation, ¶ 60.
[34] KHSA at 5, attached as UAE Exhibit RR 1.20.

minimize adverse downstream impacts. In my view, construction of a new fish hatchery falls squarely into this category.

Q. DOES RMP CONCUR WITH UAE'S INTERPRETATION OF THE 2012 SETTLEMENT STIPULATION?

A. No. In response to discovery, RMP contends that it "understands the terms of the stipulation to mean that Utah customers would not be allocated costs of physical dam removal for the Lower Klamath Project hydroelectric facilities that were to be funded through the 'State Cost Cap.'" RMP further contends that "Facilities Removal" as defined in the KHSA does not include the implementation of the KHSA Interim Measures, and that the implementation of Interim Measures under the KHSA is not an aspect of "Facilities Removal" or related dam removal activities. The Company also maintains that the purpose of the KHSA Interim Measures was to mitigate the ongoing environmental impacts of the Klamath facilities while they continued to generate low-cost power for the benefit of customers.[35] I will address each of these contentions in turn for the purpose of defending the reasoning for my adjustment.

Q. DOES THE 2012 SETTLEMENT STIPULATION LIMIT THE EXCLUSION OF THE COSTS ALLOCATED TO UTAH CUSTOMERS TO ONLY THE COST OF THE PHYSICAL REMOVAL OF DAMS FUNDED THROUGH THE STATE COST CAP?

A. No. As plainly stated in the agreement, the exclusion covers not just dam removal costs but extends to "removal related" costs and includes, but *is not limited to*, the State Cost

[35] RMP Response to Data Request OCS 23.2, included in UAE Exhibit RR 1.18.

Cap. Thus, even if removal and removal-related costs are in excess of the State Cost Cap, such costs should not be allocated to Utah.

Q. DOES THE DEFINITION OF "FACILITIES REMOVAL" IN THE KHSA STATE THAT IT EXCLUDES THE KHSA INTERIM MEASURES?

A. No.

Q. DOES THE DEFINITION OF "INTERIM MEASURES" IN THE KHSA STATE THAT IT IS NOT A CATEGORY OF FACILITIES REMOVAL?

A. No. Moreover, a review of the text describing the "Interim Measures" makes clear that they include facilities removal and removal-related obligations.[36]

Q. DOES THE 2012 SETTLEMENT STIPULATION ALLOW FOR RECOVERY FROM UTAH CUSTOMERS OF COSTS ASSOCIATED WITH THE OPERATIONS AND MAINTENANCE ("O&M") OF THE KLAMATH PROJECT FOR CONTINUED GENERATION?

A. Yes.

Q. DO YOU BELIEVE IT IS REASONABLE TO CONSTRUE THE CONSTRUCTION OF THE FALL CREEK HATCHERY TO BE AN ASPECT OF O&M ASSOCIATED WITH CONTINUED GENERATION OF POWER FROM THE KLAMATH PROJECT?

A. No. At a basic accounting level, O&M is considered an expense, not a capital expenditure. But more substantively, it strains credulity to associate the Fall Creek Hatchery with "continued generation" from the Klamath Project. The Fall Creek Hatchery did not go

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[36] *See, e.g.*, KHSA at D-5 to D-7 (discussing Interim Measures 18-20, each of which identifies obligations triggered by facilities removal). The KHSA is attached as UAE Exhibit RR 1.20.

"into service" until March 2024 – after the Klamath Project *ceased* generating power in January 2024. The obligation to construct the fish hatchery is clearly a mitigation action intended to minimize adverse downstream impacts as a consequence of the permanent removal of the Iron Gate Dam. The Company's own description of the project makes clear that the construction and operation of the Fall Creek Hatchery is necessitated by removal of the Iron Gate Dam.[37]

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE RECOVERY OF THE FALL CREEK HATCHERY COSTS IN UTAH RATES?

A. Both the rate base and O&M expense associated with the Fall Creek Hatchery should be excluded from Utah rates consistent with the requirements of the 2012 Settlement Stipulation approved by the Commission.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR FALL CREEK HATCHERY ADJUSTMENT?

A. The resulting impact from my Fall Creek Hatchery adjustment is a reduction of **$2,495,883** to the Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.4.

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[37] *See* Exhibit RMP___(SEM-3), page 8.5.35.

VI. KLAMATH REGULATORY ASSET/KLAMATH-RELATED TRANSMISSION

Q. PLEASE PROVIDE SOME BACKGROUND ON THE KLAMATH REGULATORY ASSET IN THIS CASE AND HOW IT RELATES TO THE RATEMAKING TREATMENT OF KLAMATH-RELATED COSTS APPROVED IN RMP'S LAST GENERAL RATE CASE.

A. In the last general rate case, RMP was allowed to recover the following items in rates related to the Klamath Hydroelectric Plant:

- Depreciation expense for the final depreciable year (2022) of the Klamath Dam Facilities, pursuant to the 2012 Settlement Stipulation, in a Utah-allocated amount of $3,340,339;[38]
- Regulatory asset amortization of the final year (2022) of Klamath-related relicensing and process costs, pursuant to the 2012 Settlement Stipulation, in a Utah-allocated amount of $4,268,426;[39] and
- Projected capital additions related to the ongoing operation of the Klamath Hydroelectric Facility in a Utah-allocated amount of $1,756,467, amortized over five years.[40] In this proceeding, RMP refers to this item as the Klamath Regulatory Asset.

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[38] See UAE Exhibit RR 1.5, p. 3. The total Company depreciation annual expense was $7,592,111. *Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 20-035-04 (hereafter "2020 GRC"), Direct Testimony of Steven R. McDougal, Exhibit RMP___(SRM-3), page 8.10.3.
[39] *See* UAE Exhibit RR 1.5, p. 4. 2020 GRC, Exhibit RMP___ (SRM-3), p. 8.10.2.
[40] The total Company projected capital additions in the 2020 GRC were $3,992,196. *See* 2020 GRC, Exhibit RMP___(SRM-3), p. 8.10.4.

In this case, RMP has updated the amount of its Klamath-related capital additions (the last item referenced above), but also explains that this asset has been rebooked from plant-in-service to a regulatory asset.[41] In response to discovery, RMP explains that from October 2019 through April 2023 (the time of conversion to a regulatory asset) the amount of Klamath-related capital additions totaled $7,019,826 (total Company).[42] Taking into account the net capital additions since the last general rate case, RMP proposes in this case to amortize the updated balance over five years, which amounts to $536,352 per year on a Utah-allocated basis.[43]

Q. DO YOU HAVE ANY CONCERNS ABOUT THE CONTINUED RECOVERY OF KLAMATH-RELATED CAPITAL ADDITIONS IN THIS CASE?

A. Yes. As I noted above, current Utah rates include the recovery of $3,340,339 in Klamath-related depreciation expense and $4,268,426 in Klamath-related relicensing and process costs, totaling $7,608,765 per year. These obligations were fully paid off at the end of 2022, but have continued to be recovered in rates throughout 2023 and 2024. I find it difficult to justify increasing the revenue requirement in this case to recover the cost of Klamath-related capital additions that were incurred while customers continued to pay for expired Klamath obligations in rates. In effect, the piecemeal accounting of Klamath-related costs, when viewed as a whole, results in an over-recovery of Klamath-related costs from Utah customers relative to Utah's obligations. On the one hand, new Klamath capital additions are scrupulously booked, depreciated, and included in the test period revenue requirement on a going-forward basis, while on the other hand, major Klamath revenue

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[41] *See* Direct Testimony of Shelley E. McCoy, lines 924-938.
[42] RMP Response to Data Request OCS 6.1, included in UAE Exhibit RR 1.18.
[43] *See* Exhibit RMP___(SEM-3), pp. 8.10, 8.10.2.

obligations expire but continue to be recovered in rates. Taken together, the combination is a recipe for over-recovery.

Q. WHEN ASSETS ARE FULLY PAID OFF IN BETWEEN RATE CASES, ISN'T IT STANDARD PRACTICE FOR THE REVENUES BEING RECOVERED TO REMAIN IN RATES?

A. Absent a deferral creating a regulatory liability, yes.

Q. ARE THERE ANY FACTORS THAT DISTINGUISH THIS SITUATION FROM STANDARD PRACTICE?

A. Yes. There are two factors that distinguish this situation. First, the payoff of the 2012 balances of both the Klamath Dam Facilities and the Klamath-related relicensing and process costs were subject to explicit Commission-approved terms that completed those obligations in December 2022.[44] Second, the Company has continued to book – and in this proceeding seek recovery of – new Klamath-related costs. The conjunction of these two factors – the continued recovery in Utah rates of fully-amortized Klamath assets coupled with the Company's request to recover new Klamath-related costs from Utah customers – creates a special circumstance that warrants special consideration from the Commission.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE KLAMATH REGULATORY ASSET?

A. I recommend that the revenues that Utah customers have been paying for expired Klamath-related obligations since January 1, 2023 be used to offset the cost of the Klamath regulatory asset.

[44] Docket No. 11-035-200, 2012 Settlement Stipulation at ¶¶ 58-59.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR ADJUSTMENT TO OFFSET THE KLAMATH REGULATORY ASSET WITH OVER-CONTRIBUTED KLAMATH REVENUES?

A. The resulting impact from my adjustment is a **$630,034** reduction to Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.5.

Q. AFTER OFFSETTING THE KLAMATH REGULATORY ASSET WITH THE REVENUES THAT UTAH CUSTOMERS HAVE CONTINUED TO CONTRIBUTE TOWARD THE EXPIRED KLAMATH OBLIGATIONS, WHAT IS THE REMAINING BALANCE OF OVER-CONTRIBUTED REVENUES AT THE START OF THE TEST PERIOD?

A. $13,630,822. This calculation is shown in UAE Exhibit RR 1.5, page 5, and does not include an accrual of interest. In addition, there will be a further contribution of $1,092,674 from Utah customers for the expired Klamath obligations during the first several weeks of the 2025 test period, *i.e.*, from January 1, 2025 through February 22, 2025, up until the start of the rate effective period.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE DISPOSITION OF THIS REMAINING BALANCE?

A. Yes. In addition to the Klamath Regulatory Asset, RMP is seeking recovery in this case of other new costs related to the Klamath facilities and their removal and has also identified new costs for which the Company is not seeking recovery at this time. These new costs include:

- Fall Creek Hatchery - $36.5 million of new plant-in-service (total Company) (discussed in a separate section of my testimony above);

- Klamath-related transmission investment (OTP0189) – $20.0 million of new plant-in-service (total Company);
- Additional costs booked to the Klamath Regulatory Asset in 2024 ($8.0 million total Company)[45] for which RMP is not seeking recovery in this case.[46]

I recommend that the remaining balance of over-contributed revenues be used to buy down Utah's allocated share of the second of these two items –the Klamath-related transmission investment (OTP0189). As described by RMP, this project completes the facilities needed to maintain PacifiCorp's transmission system following the decommissioning of the six Klamath River hydro generating resources. To the extent the Commission determines this project to be a recoverable investment in Utah, it is appropriate in my opinion to apply the remaining balance of over-contributed revenues to buy down Utah's allocated share of this Klamath-related cost.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR ADJUSTMENT TO OFFSET THE KLAMATH-RELATED TRANSMISSION INVESTMENT WITH OVER-CONTRIBUTED KLAMATH REVENUES?

A. This adjustment will reduce the Utah revenue requirement deficiency in this case by approximately **$58,079**. This adjustment is shown in UAE Exhibit RR 1.6. The revenue requirement of this adjustment is relatively small in this case because most of the transmission plant involved is not expected to come into service until December 2025. However, the buy-down of the plant would represent a permanent reduction in rate base and would have a greater impact in later years.

[45] RMP Response to Data Request OCS 6.2, included in UAE Exhibit RR 1.18.
[46] RMP Response to Data Request OCS 11.9, included in UAE Exhibit RR1.18.

Q. WHAT IS THE REMAINING BALANCE OF OVER-CONTRIBUTED REVENUES AFTER OFFSETTING THE KLAMATH CAPITAL ADDITIONS AND BUYING DOWN THE KLAMATH-RELATED TRANSMISSION INVESTMENT?

A. There will be a remaining Utah balance of $5,734,248 as of February 23, 2025, as shown in UAE Exhibit RR 1.6, page 3, line 27.

Q. ARE THERE ANY ADDITIONAL KLAMATH-RELATED COSTS TO WHICH THIS BALANCE CAN REASONABLY BE APPLIED?

A. I noted above that RMP has booked $8.0 million in total Company costs to the Klamath Regulatory Asset in 2024, but the Company is not seeking recovery of these costs in this case. To the extent that these most recently booked costs are eligible for recovery in Utah, a portion of the remaining balance of over-contributed revenues could be used to buy down, or extinguish, Utah's allocated share of these additions to the Klamath Regulatory Asset.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS IF THE COMMISSION DOES NOT ADOPT YOUR PRIMARY RECOMMENDATION TO APPLY THE REMAINING BALANCE OF OVER-CONTRIBUTED REVENUES TO BUY DOWN UTAH'S ALLOCATED SHARE OF THE KLAMATH-RELATED TRANSMISSION INVESTMENT?

A. Yes. As I discussed previously, I am recommending against including any costs associated with the Fall Creek Hatchery in the Utah revenue requirement because I believe doing so would be inconsistent with the terms of the 2012 Settlement Stipulation. However, if the Commission disagrees with my recommendation on that matter and opts not to apply the remaining balance of over-contributed revenues to buy down Utah's allocated share of the

Klamath-related transmission investment, then those funds could be used to buy down Utah's allocated share of the Fall Creek Hatchery instead.

VII. CHOLLA UNIT 4 SEVERANCE AND SAFE HARBOR LEASE COSTS

Q. WHAT COSTS RELATED TO THE CLOSED CHOLLA UNIT 4 PLANT IS RMP SEEKING TO RECOVER IN THIS CASE?

A. RMP seeks to recover non-union employee severance costs of $1,950,000 (total Company) and a Safe Harbor Lease termination cost of $94,579 (total Company) associated with the closure of Cholla Unit 4. RMP proposes to amortize these costs over three years.

By way of background, Cholla Unit 4 ceased operations December 31, 2020. In the 2020 general rate case, the Commission approved RMP's proposal to buy down the undepreciated plant balance, closure costs, and estimated decommissioning costs of Cholla Unit 4 using dollars from the Sustainable Transportation and Energy Plan ("STEP") Depreciation Fund. $145.9 million in STEP funds were used for this purpose. Of that amount $125.1 million was used for the remaining Utah-allocated plant balances and $20.8 million for decommissioning costs.[47]

Also in the 2020 general rate case, the Commission approved RMP's request to establish a deferral account to defer and amortize certain costs associated with closing Cholla Unit 4. The costs specified by RMP to be included in this deferral account were (a) incurred Construction Work In Progress; (b) the value of estimated obsolete materials and supplies; and (3) liquidated damages, all of which RMP proposed to defer and amortize

[47] *See* 2020 GRC, Direct Testimony of Steven R. McDougal, lines 628-637; 847-873.

through the end of the plant's original depreciable life in April 2025. RMP also proposed using the deferral account to true-up any differences in final closing costs and decommissioning costs from its estimates in that general rate case.

Q. IN SEEKING APPROVAL FOR THE DEFERRAL ACCOUNT, DID RMP REQUEST APPROVAL TO DEFER EMPLOYEE SEVERANCE EXPENSE OR A SAFE HARBOR LEASE COST?

A. No. Employee severance costs were not among the items identified by RMP in its Cholla Unit 4 deferral request.

Q. DO YOU BELIEVE IT IS APPROPRIATE TO INCLUDE THESE COSTS FOR RECOVERY IN THIS CASE?

A. No. As a form of single-issue ratemaking, deferred accounting is used very sparingly in Utah. In the last general rate case, the Commission approved RMP's request for deferred accounting for the three specific items identified above, as well as for truing-up any differences in final closing costs and decommissioning costs relative to the Company's estimates, which also did not include severance costs or a Safe Harbor Lease termination cost. I recommend that the Cholla Unit 4 non-union employee severance cost and Safe Harbor Lease cost be disallowed from the revenue requirement.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR CHOLLA UNIT 4 ADJUSTMENT?

A. The resulting impact from my adjustment is a **$432,376** reduction to Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.5.

VIII. GENERATION OVERHAUL

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR GENERATION OVERHAUL EXPENSE.

A. RMP normalizes generation maintenance expense over a four-year historical period for fossil generation plant and substitutes the normalized value for the actual test year expense in determining the proposed revenue requirement. For the purposes of this case, RMP uses the historical period, 2020-2023.

Q. DO YOU BELIEVE IT IS APPROPRIATE TO NORMALIZE GENERATION MAINTENANCE EXPENSE?

A. Yes. Generation maintenance includes performing unit overhauls. The overhaul schedule for a generating facility generally follows a multi-year cycle. Consequently, for a given plant, a year in which expense for a planned overhaul is high may be followed by years of much lower expense. For ratemaking purposes, provided the actual results are within a range of reasonableness, it is preferable to use a normalization technique for this expense item because the actual overhaul expense in a given test period may not be representative of annual overhaul expense over time. A reasonable normalization technique to set test period overhaul expense is to use a historical average over a multi-year period rather than the expense experienced for a single year. This approach smooths out the otherwise volatile pattern of annual costs that is typical of generation overhaul expense.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE NORMALIZATION CALCULATION PERFORMED BY RMP?

A. Yes. My concern involves the treatment of the Jim Bridger Unit 1 and Unit 2 facilities. These facilities have been converted from coal-fired units to gas-fired, which in general should have lower overhaul costs than coal units.[48] For the purposes of the Company's generation overhaul adjustment, RMP uses the historical overhaul expense for Jim Bridger Unit 2 in 2022, when it was still a coal unit.[49] While in general I fully support the Company's use of actual historical data, an exception is appropriate for a new unit or a converted unit. In such situations, a four-year projection of overhaul expense can reasonably be used in calculating the adjustment. I note that this is the approach the Company used in its 2007 general rate case for calculating the generation overhaul costs of its Lakeside and Currant Creek generating units, which were new facilities at that time.[50] The Company's approach was accepted by the Commission in its final Order in that case.[51]

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING GENERATION OVERHAUL NORMALIZATION?

A. For Jim Bridger Units 1 and 2, which have been converted from coal to gas, a four-year projection of overhaul costs as gas units should be substituted for the four years of historical costs as coal units. In response to discovery, RMP provided projected overhaul costs for Jim Bridger Units 1 and 2 for the four-year period, 2024-2027. I recalculated RMP's generation overhaul adjustment using this information, which is presented in in UAE Exhibit RR 1.8.

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[48] RMP Response to Data Request UAE 12.1(c), included in UAE Exhibit RR 1.18.

[49] In its adjustment, RMP does not include any generation overhaul expense for Jim Bridger Unit 1 for the period 2020-2023.

[50] *See In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 07-035-93, Rebuttal Testimony of Steven R. McDougal, lines 125-135.

[51] *See* Docket No. 07-035-93, Report and Order on Revenue Requirement (Aug. 11, 2008) at 82.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR GENERATION OVERHAUL ADJUSTMENT?

A. The resulting impact from my adjustment is a **$412,847** reduction to Utah revenue requirement deficiency. This adjustment is also shown in UAE Exhibit RR 1.8.

IX. <u>INFLATION IN NON-LABOR O&M EXPENSE</u>

Q. WHAT ADJUSTMENT ARE YOU PROPOSING WITH RESPECT TO NON-LABOR O&M EXPENSE?

A. I am proposing an adjustment to remove the inflation escalator applied by RMP to its non-labor O&M expense.

Q. PLEASE EXPLAIN THE BASIS FOR YOUR ADJUSTMENT.

A. The non-labor O&M expense projected by RMP for the test period contains a cost escalation component to reflect projected inflation for the period extending from December 2023 through December 2025.[52]

To apply this cost escalator, RMP starts with its actual non-labor O&M expense for the base period, January to December 2023. RMP then applies discrete adjustments that are reflected elsewhere in its filing to calculate its adjusted base period non-labor O&M expenses. To its adjusted base period costs, RMP applies a series of escalation factors based on indices from an April 2024 study by IHS Markit.[53]

From a ratemaking perspective, I have two serious concerns with this approach.

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[52] *See* Exhibit RMP___(SEM)-3, pp. 4.8 – 4.8.6.
[53] *See* Direct Testimony of Shelley E. McCoy, lines 650-662.

First, at a broad policy level, I have concerns about regulatory pricing formulations that cause or reinforce inflation. This occurs when *projections* of inflation are built into formulas that are used to set administratively determined prices, such as utility rates. In the context of a future test year, this practice builds projected inflation into utility rates before the cost escalation even occurs. Such pricing mechanisms help to make inflation a self-fulfilling prophecy. As a matter of public policy, this is a serious concern. It is one thing to adjust for inflation after the fact; it is another to help guarantee it. For this reason, I believe that regulators should use extreme caution before approving prices that guarantee inflation before it occurs.

Q. WHAT IS YOUR SECOND MAJOR CONCERN?

A. A related, but distinct, concern involves the building of a formulaic "cost cushion" into the Company's test period costs. While the specific indices used in RMP's direct filing in this case result in only a minor increase to the Utah revenue requirement, the practice of escalating O&M expenses based on inflation factors is troubling as a general principle. Allowing this type of systemic uplift in rates goes well beyond the basic justification for using a projected test period, which is to ameliorate the effect of regulatory lag on the recovery of investment in new plant.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR NON-LABOR O&M ADJUSTMENT?

A. The resulting impact from my non-labor O&M adjustment is a **$71,333** reduction to the Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.9.

X. ANNUAL INCENTIVE COMPENSATION FOR EMPLOYEES

Q. PLEASE DESCRIBE RMP'S AIP.

A. RMP provides an AIP for its eligible employees. Under the AIP, eligible employees earn discretionary cash incentive awards, which are determined on a case-by-case basis. The Company's overall performance is measured on a "PacifiCorp Scorecard," and used as a multiplier in determining AIP awards.[54] The Key Performance Indicators of the PacifiCorp Scorecard include [redacted]

Q. WHAT HAS RMP PROPOSED WITH RESPECT TO INCENTIVE COMPENSATION?

A. RMP is proposing to include 100% of the annual incentive compensation expense in rates, based on the three-year average proportion of AIP costs relative to eligible wages for years 2021 through 2023.[55] RMP applies this proportion to its proposed test year eligible wages to calculate its requested test year AIP expense.

Q. IN YOUR OPINION, IS IT APPROPRIATE TO RECOVER THE COST OF ANNUAL INCENTIVE COMPENSATION PLANS IN UTILITY RATES?

A. It can be appropriate to recover the cost of annual incentive compensation plans in utility rates, but only to the extent that the compensation in such plans is not excessive and to the extent that the goals of such plans are not tied to utility financial performance, but rather to goals such as customer satisfaction, operating efficiency, and safety. While rewarding

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[54] *See* RMP response to GRC Filing Requirement R746-700-22.D.25, Attachment R746-700-22.D.25-3.
[55] *See* Exhibit RMP___(SEM-3), page 4.2.6.

employees for *financial* performance can be entirely appropriate, the responsibility for funding such awards rests most appropriately with shareholders, who are the primary beneficiaries when the Company meets or exceeds financial targets.

Q. IS YOUR RECOMMENDATION CONSISTENT WITH PAST FINDINGS OF THE COMMISSION?

A. Prior to the Commission's order in RMP's last rate case, the Commission consistently required that incentive compensation that is tied to financial performance be funded by shareholders. The foundations of the Commission's policy in this regard are discussed at length in the Commission's Order in Docket No. 95-049-05, issued November 27, 1995:

> In Docket No. 92-049-05, the Division sought disallowance of the expenses of [US West, Inc.'s] long-term incentive compensation plan for executives. The plan consisted of stock options and job performance shares, both of which provide additional compensation to the Company executives if US West, Inc.'s stock price increases in the long run. The Commission determined that costs of incentive bonus plans could be recovered from ratepayers if the plans were based on criteria which benefit ratepayers such as individual performance, productivity, and customer service. Plans based on financial criteria, benefitting shareholders, could not be recovered from ratepayers. The Commission dismissed the Company claim that bonuses tied to financial performance indirectly benefit ratepayers through higher stock prices and reduced cost of service. The Commission stated: 'The indirect ratepayer benefit claimed by the Company is little more than words. We wish to see specific criteria of the sort just mentioned [individual performance, productivity, and customer service] guiding the program before we will consider the expenses suitable for recovery from ratepayers' (Report and Order, April 15, 1993, Docket No. 92-049-05, page 45). The Commission disallowed recovery of the expenses of the executive long-term incentive compensation.

After discussing the foundations of its policies on incentive compensation, the Commission went on to reaffirm them:

> The Commission has previously heard and rejected the argument from PacifiCorp and Mountain Fuel, as well as USWC, that increased income arising from incentive compensation reduces revenue requirement. Since

> financial goals can be achieved at the expense of customer service, the Commission reiterates its policy that an acceptable incentive compensation plan, to be recoverable in rates, must have as its primary objective customer service goals, not financial goals.

Q. WHAT DID THE COMMISSION DETERMINE ON THIS SUBJECT IN THE LAST RATE CASE?

A. Departing from established practice, in the 2020 general rate case the Commission declined to remove the portion of RMP's AIP expense tied to financial performance from the revenue requirement. The Commission found that the AIP goal categories predominantly benefitted customers and that RMP's employee compensation generally reflected the market rate.[56]

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING RECOVERY OF ANNUAL INCENTIVE COMPENSATION EXPENSE?

A. I recommend that shareholders – and not customers – fund the share of RMP's annual incentive expense that is related to the Company's financial performance. According to discovery,[57] [redacted] My adjustment reduces RMP's Utah revenue requirement deficiency by approximately

[56] 2020 GRC, Order (Dec. 30, 2020), at pp. 28-29.
[57] *See* RMP response to Data Request OCS 5.4, Attach OCS 5.4, PacifiCorp YE Scorecards 2021-2023 CONF, included in CONF UAE Exhibit RR 1.19.

$433,857 relative to the Company's filed case, including the estimated payroll tax impact. This adjustment is shown in UAE Exhibit RR 1.10, a portion of which is Confidential.

XI. CORRECTION OF RMP ERRORS (NON-NET POWER COST)

Q. PLEASE DISCUSS THE ERROR CORRECTIONS YOU INCORPORATE IN YOUR REVENUE REQUIREMENT CALCULATION.

A. I have incorporated corrections to the following items that have been acknowledged by RMP:

1) RMP used incorrect allocation factors to determine the Utah-allocated base period wildland fire O&M expenses recorded in FERC Accounts 560 and 580 incorporated in the Wildland Fire O&M adjustment.[58] Correcting this error *increases* the Utah revenue requirement deficiency by **$1,047,992**. This adjustment is shown in UAE Exhibit RR 1.11.

2) Expenses associated with the wildland fire deferral recorded in FERC Account 590 were inadvertently included in the general rate case.[59] Removing these expenses from the base revenue requirement reduces the Utah revenue requirement deficiency by **$6,417,975.** This adjustment is shown in UAE Exhibit RR 1.12.

3) The Electric Vehicle Infrastructure Program (EVIP) amortization expense was inadvertently included in the general rate case.[60] Removing this expense reduces

[58] *See* RMP response to Data Request OCS 8.20, Attachment OCS 8.20-2 1st Revised, excerpted in UAE KCH RR 1.18.
[59] *See* RMP response to Data Request OCS 8.22, Attachment OCS 8.22-1, excerpted in UAE Exhibit RR 1.18.
[60] *See* RMP response to Data Request OCS 8.24, Attachment OCS 8.24, excerpted in UAE Exhibit RR 1.18.

the Utah revenue requirement deficiency by **$2,191,266**. This adjustment is shown in UAE Exhibit RR 1.13.

4) In addition to the error corrections itemized above, I include an update to the actual amount of the Deer Creek Recovery Royalties paid by the Company, in place of the estimate included in the revenue requirement.[61] This adjustment reduces the Utah revenue requirement deficiency by **$107,717**. This adjustment is shown in UAE Exhibit RR 1.14.

XII. TRANSMISSION REVENUES

Q. HOW DOES RMP TREAT TRANSMISSION REVENUES FROM THIRD-PARTY WHEELING IN DETERMINING THE REVENUE REQUIREMENT?

A. RMP allocates a share of third-party wheeling revenue to the Utah jurisdiction, which is then used as an offset against the Utah revenue requirement.

Q. DO YOU HAVE ANY CONCERNS ABOUT RMP'S CALCULATION OF THE TRANSMISSION REVENUE CREDIT?

A. Yes. In making this calculation, RMP is not using the current FERC-approved rate for transmission service for the first five months of the 2025 test period. The current FERC-approved rate is $4,460.80 per MW-month, but RMP is using a rate of $3,494.49 per MW-month in calculating the transmission revenue credit for the period January 2025 through May 2025.[62] My concern is directed only to the first five months of 2025 because I understand that new FERC-approved formula transmission rates will go into

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[61] *See* RMP responses to Data Requests OCS 5.46 and OCS 7.25, included in UAE Exhibit RR 1.18.
[62] *See* RMP Redacted Response to Data Request OCS 22.2, included in UAE Exhibit RR 1.18.

effect in June 2025. For the period June 2025 through December 2025, RMP is using a projected rate of $4,734.49 per MW-month,[63] which I am not challenging.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE CALCULATION OF THE TRANSMISSION REVENUE CREDIT?

A. I recommend that the Commission order RMP to use the current FERC-approved rate of $4,460.80 per MW-month for the test period months of January through May 2025 in calculating the transmission revenue credit.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR TRANSMISSION REVENUE CREDIT ADJUSTMENT?

A. The resulting impact from my adjustment is a **$6,033,309** reduction to Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.15, portions of which are confidential.

XIII. <u>NET POWER COST – WASHINGTON CLIMATE COMMITMENT ACT</u>

Q. WHAT IS THE CLIMATE COMMITMENT ACT?

A. The Climate Commitment Act ("CCA") was passed by the Washington Legislature in 2021. One of the features of the CCA is that it directs the state Department of Ecology to establish rules establishing a cap and invest program. The adopted rules, which went into effect January 1, 2023, require certain entities to purchase greenhouse gas allowances associated with carbon emissions from emitting resources. The CCA applies to all emissions produced from generation resources located within the State of Washington,

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[63] *See id*. *See also* RMP Confidential 1st Revised Response to Data Request OCS Data Request 9.2, Attachment OCS 9.2 1st REVISED CONF, included in CONF UAE Exhibit RR 1.19.

including the Company's Chehalis power plant, which is a 520-MW gas-fired combined-cycle facility located in Lewis County, Washington.

An implication of the CCA for PacifiCorp is that it must purchase and retire allowances for its greenhouse gas emissions from Chehalis, but with an important exception. To minimize the impact of the CCA on Washington retail customers, the Department of Ecology allocates free allowances to electric utilities, including PacifiCorp, to serve their Washington retail loads. Thus, only the portion of Chehalis output that is used for the benefit of the Company's non-Washington customers, including Utah customers, is charged for the cost of allowances.

Q. IS THE COST OF CCA EMISSION ALLOWANCES INCLUDED IN THE COMPANY'S REQUESTED REVENUE REQUIREMENT IN THIS CASE?

A. Yes. The test period net power cost includes [redacted] for CCA emission allowances on total Company basis.[64] This impact was calculated by RMP using an estimated allowance price of $11.14/MWh for calendar year 2025 based on auction results from March 6, 2024.[65]

Q. ARE THERE OTHER IMPACTS ON NET POWER COST RESULTING FROM THE CCA ALLOWANCES OTHER THAN THE DIRECT COST OF THE ALLOWANCES?

A. Yes, in addition to the direct cost of the allowances, the incremental cost of the allowances impacts the Company's least-cost dispatch of its generation fleet and market purchases, causing what would otherwise be higher-cost resources to be dispatched ahead of Chehalis.

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[64] *See* RMP Confidential Response to DPU Data Request 30.2, included in CONF UAE Exhibit RR.1.19.
[65] *See* Direct Testimony of Ramon J. Mitchell, lines 354-357.

Q. WHAT IS THE OVERALL IMPACT ON NET POWER COST TAKING INTO ACCOUNT THE DIRECT COST OF THE ALLOWANCES PLUS THE EFFECT ON DISPATCH?

A. According to documentation provided by the Company, the combined effect increases net power cost by $29 million on a total Company basis,[66] $12.9 million of which is allocated to Utah.

Q. HAS PACIFICORP TAKEN ANY ACTIONS TO ADDRESS THE IMPACT OF THE CCA ON ITS NON-WASHINGTON CUSTOMERS?

A. Yes. On January 4, 2024, the Company filed an amended complaint for declaratory and injunctive relief with the US District Court, Western District of Washington at Tacoma seeking an injunction that would expand the availability of no-cost allowances to all customers who receive power from Chehalis regardless of the customer's state of residence; or, in the alternative, an injunction prohibiting the Department of Ecology from enforcing, or seeking to enforce, the provisions of the CCA requiring PacifiCorp to acquire allowances for its out-of-Washington customers of Chehalis. It is my understanding that the Company's complaint was dismissed.

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE TREATMENT OF THE WASHINGTON CCA COSTS IN UTAH RATES?

A. Yes. I recommend that the Washington CCA costs, including the incremental cost of altering the Company's dispatch, be disallowed from the Utah test period revenue requirement. Although I am not an attorney, allocating the cost of allowances only to non-

[66] *See* Direct Testimony of Ramon J. Mitchell, lines 364-366.

Washington jurisdictions strikes me as unduly discriminatory for ratemaking purposes. But more fundamentally, the CCA should be viewed as a Washington state policy action that should not implicate Utah rates. The 2020 Protocol to the Multi-State Process, which was approved and extended by the Commission,[67] and predates the CCA, does not have a provision dealing directly with the CCA. Of the categories of costs identified in the 2020 Protocol, the CCA appears to most resemble a State-Specific Initiative, which according to Section 5.7 of the 2020 Protocol, should be situs-assigned to the state adopting the initiative.

Q. HAVE OTHER JURISDICTIONS DISALLOWED THE COSTS OF THE CCA FROM THEIR RESPECTIVE REVENUE REQUIREMENTS?

A. Yes. CCA costs were disallowed by the Oregon Public Utilities Commission in Docket No. UE 420[68] and by the Wyoming Public Service Commission in Docket No. 20000-633-ER-23.[69]

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR WASHINGTON CCA NET POWER COST ADJUSTMENT?

A. The resulting impact from my adjustment is a **$13,038,382** reduction to Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.16, portions of which are confidential.

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[67] *Application of Rocky Mountain Power for an Extension to the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 23-035-20, Order Approving Extension of the 2020 Protocol (July 27, 2023).
[68] *See In the Matter of PacifiCorp, dba Pacific Power, 2024 Transition Adjustment Mechanism*, OPUC Docket No. UE 420, Order No. 23-404 at 8-10, attached as UAE Exhibit RR 1.21.
[69] *See In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $140.2 Million Per Year or 21.6 Percent and to Revise the Energy Cost Adjustment Mechanism*, WPSC Docket No. 20000-633-ER-23, Record No. 17252, Memorandum Opinion, Findings and Order (Jan. 2, 2024) ¶ 211, attached as UAE Exhibit RR 1.22.

XIV. <u>NET POWER COST – CORRECTION TO RMP FORWARD PRICE CURVE</u>

Q. PLEASE DESCRIBE YOUR ADJUSTMENT CORRECTING FOR AN ERROR IN RMP'S FORWARD PRICE CURVE.

A. In response to discovery, RMP indicated that it had found an error in the development of its Official Forward Price Curve for the 2025 test period involving the incorporation of off-peak Intercontinental Exchange quotes into the broker average. The average Mid-Columbia off-peak price loaded for the test period was approximately $67.79 per MWh, whereas the correct average price was $67.61 per MWh. Similarly, Palo Verde prices for the test period were loaded at an average off-peak price of $61.94 per MWh, while the correct average price was $61.87 per MWh.[70] This error results in an overstatement of total Company net power costs by $6.7 million.[71]

Correcting this error results in a **$3,063,798** reduction to Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.17.

XV. <u>WILDFIRE EXCESS LIABILITY INSURANCE EXPENSE</u>

Q. HOW HAVE YOU TREATED WILDFIRE EXCESS LIABILITY EXPENSE IN YOUR REVENUE REQUIREMENT TESTIMONY?

A. My understanding is that the Commission has consolidated RMP's request for recovery of anticipated test period costs associated with excess liability insurance premiums in this general rate case with the Company's request for a deferred accounting order for excess

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[70] *See* RMP Response to Data Request DPU 8.3, included in UAE Exhibit RR 1.18.
[71] *See* RMP Response to Data Request OCS 19.2, included in UAE Exhibit RR 1.18.

liability insurance premiums in Docket No. 23-035-40. Consistent with that decision, UAE's analysis and recommendations on this subject will be presented in the consolidated docket in accordance with the schedule adopted by the Commission.

Q. HOW IS RMP PROPOSING TO RECOVER ITS EXCESS WILDFIRE LIABILITY INSURANCE PREMIUMS IN ITS CASE?

A. RMP is proposing to recover these costs through a new Insurance Cost Adjustment ("ICA") mechanism. In amended direct testimony, RMP requested an ICA recovery of $92.9 million, representing the Company's allocation of total Company costs of $210 million to the Utah jurisdiction.[72] Because RMP is proposing to recover wildfire excess liability insurance costs through the ICA, the Company removed these costs from base rates in its filing.

Q. HAS RMP UPDATED THE AMOUNT OF ITS EXPECTED EXCESS WILDFIRE LIABILITY INSURANCE PREMIUMS SINCE FILING ITS AMENDED TESTIMONY?

A. Yes. In response to discovery, RMP has updated the total Company amount to $189 million.[73] I estimate that this corresponds to $83.6 million on a Utah-allocated basis.[74]

Q. DO YOU SUPPORT ADOPTION OF THE ICA MECHANISM?

A. No. I recommend against adoption of the ICA to the extent it would be used as a mechanism to change the revenue recovered from customers for wildfire excess liability insurance costs or self-insurance costs between rate cases. RMP witness Ms. Joelle R.

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[72] *See* Amended Direct Testimony of Joelle R. Steward, lines 121-126. In its initial direct filing, RMP requested ICA recovery of $81.4 million, based on a total Company cost of $183.9 million. *See* Exhibit RMP___(SEM-10), p. 2.
[73] *See* RMP Response to Data Request DPU 47.4, included in UAE Exhibit RR 1.18.
[74] $189 million × 44.2576% SO Factor.

Steward explains that separating recovery for this expense will enable the Company to track the costs and collections and annually procure insurance for third-party liability using the most economical combination of commercial insurance and self-insurance through a new insurance mechanism that the Company is developing.[75] I agree with Ms. Steward that a self-insurance option is worth investigating and that there may be periods in which a combination of commercial insurance and self-insurance is the most cost-effective option to pursue. But the details on how self-insurance would be employed are yet to be developed. And I am very concerned that the ICA would result in an open-ended cost obligation for customers. For these reasons, I recommend that the revenue requirement for wildfire excess liability insurance costs be established in this general rate case and not be subject to annual adjustment through the proposed ICA.

To the extent that future wildfire insurance costs include a self-insurance component, a mechanism to track self-insurance balances would probably be necessary. In that respect, I am not opposed to a wildfire insurance cost "mechanism," so long as it is not used as a vehicle to flow through annual revenue requirement changes to customers.

XVI. RETURN ON EQUITY ("ROE")

Q. WHAT ROE IS RMP REQUESTING?

A. RMP is requesting a return on equity of 9.65%,[76] which is the same ROE authorized by the Commission in the Company's last general rate case.

[75] *See* Direct Testimony of Joelle R. Steward, lines 342-345.
[76] *See* Direct Testimony Joelle Steward, lines 120-132.

Q. ARE YOU PRESENTING AN ADJUSTMENT FOR ROE IN YOUR TESTIMONY?

A. No. Although UAE is not presenting testimony on RMP's cost of capital, this should not be construed as an endorsement of RMP's proposal. UAE recognizes that other parties, including the Division of Public Utilities ("Division") and Office of Consumer Services ("OCS"), will be addressing this subject.

XVII. <u>PENSION SETTLEMENT ADJUSTMENTS BALANCING ACCOUNT</u>

Q. WHAT IS THE PENSION SETTLEMENT ADJUSTMENTS BALANCING ACCOUNT?

A. The Pension Settlement Adjustments Balancing Account ("PSABA") was established following the Commission's approval in RMP's last general rate case of a balancing account that would true-up the pension settlement adjustments that the Company actually recognizes with the amount it recovered in rates.[77] In that case, the Commission allowed RMP to recover Utah's allocated share of $11.9 million in settlement losses the Company anticipated incurring during the 2021 test year in rates effective January 1, 2021, although the amount of settlement losses that RMP actually included in its revenue requirement later became a subject of no small controversy when the PSABA was implemented.[78]

Q. WHAT IS THE TEST PERIOD AMOUNT THAT RMP HAS INCLUDED IN RATES IN THIS CASE FOR PENSION SETTLEMENT LOSSES?

A. Zero.

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[77] 2020 GRC, Order at 29-32.
[78] *Application of Rocky Mountain Power to Establish a Balancing Account for Pension Settlement Adjustments*, Docket No. 21-035-14, Order (Nov. 3, 2021).

Q. DID RMP HAVE ANY PENSION SETTLEMENT LOSSES IN 2023?

A. No.[79]

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE PSABA GOING FORWARD?

A. Yes. I recommend that the PSABA be discontinued. There are no pension settlement losses in the test period, nor did the Company experience any in 2023. I believe it is no longer useful to retain this single-issue ratemaking mechanism.

XVIII. DOCUMENTATION OF DATA RESPONSES RELIED ON

Q. HAVE YOU PROVIDED COPIES OF THE DATA RESPONSES YOU RELIED UPON IN PREPARING YOUR ANALYSIS?

A. Yes. Non-confidential data responses that I relied on are provided in UAE Exhibit RR 1.18. Confidential data responses that I relied on are provided in Confidential UAE Exhibit RR 1.19.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS PHASE OF THE CASE?

A. Yes, it does.

[79] *Rocky Mountain Power's Annual Report of the Pension Asset Settlement Adjustment Balancing Account*, Docket No. 24-035-25, PSABA Report (May 15, 2024).