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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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. 20-035-04**

PREFILED REDACTED DIRECT TESTIMONY OF KEVIN C. HIGGINS

The UAE Intervention Group ("UAE") hereby submits the Prefiled Redacted Direct Testimony of Kevin C. Higgins.

DATED this 2nd day of September, 2020.

JAMES DODGE RUSSELL & STEPHENS

/s/ Phillip J Russell
Phillip J. Russell
Counsel for UAE

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by email this 2nd day of September, 2020 on the following:

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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 Electi·ic Service Regulations	DOCKET NO. 20-035-04

REDACTED DIRECT TESTIMONY

AND EXHIBITS

OF

KEVIN C. HIGGINS

On Behalf of

Utah Association of Energy Users

September 2, 2020

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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 forty-three 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 210 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Colorado, 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 Company's proposed projected test period, which is the year ending December 31, 2021.

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

A. I offer the following conclusions and recommendations:

1) RMP has identified $84.3 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, 2021 or has been canceled. In my opinion, canceled plant should be excluded from the revenue requirement, as should post-2021 plant, as the latter falls outside the bounds of the projected test period. This adjustment reduces the Utah revenue requirement deficiency by **$7,120,052**.

2) The accumulated depreciation reserve associated with the 11 repowered wind projects approved by the Commission, plus Leaning Juniper, should be adjusted to reflect the depreciation expense associated with the retired assets that customers have continued to pay in rates between the time each of the wind assets was retired and January 1, 2021. This adjustment reduces the Utah revenue requirement deficiency by **$1,943,228**.

3) RMP's request to include its prepaid pension and post-retirement welfare ("PRW") assets in rate base should be rejected. This adjustment reduces the Utah revenue requirement deficiency by **$10,496,736**. In the alternative, if the Commission approves RMP's request to include these prepaid assets in rate base, the allowed return on RMP's prepaid pension and PRW assets should be set at RMP's Expected Return on Assets for these plans without a tax gross-up.

4) RMP's proposal to recover the cost of Construction Work in Progress ("CWIP") and materials and supplies associated with its retiring Cholla Unit 4 plant should be rejected as these expenditures did not result in plant that was used and useful. This adjustment reduces the Utah revenue requirement deficiency by **$1,107,764**.

5) 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 **$3,566,389.**

6) An error acknowledged by RMP in the calculation of Post-Retirement Benefits expense should be corrected. This correction reduces the Utah revenue requirement deficiency by **$708,820.**

7) Projected wage levels should reflect the 12 months ending December 31, 2021, rather than the projected wage levels at 2021 year-end, as included in RMP's adjustment. This adjustment reduces the Utah revenue requirement deficiency by **$702,798**.

8) 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 approximately [redacted] relative to the Company's filed case.

9) RMP's proposed test period wage and benefits expense should be reduced. RMP's full-time equivalent ("FTE") employee count has declined relative to the average number of FTEs in the base period, which RMP uses in its forecast of test period wage and benefits expense. I recommend basing test period wage and benefits expense on more recent average employment levels for the year-ended May 2020. Accordingly, I have reduced test period wage and benefits expense to account for a reduction of 35.2 FTE employees across the Company. This adjustment reduces the Utah revenue requirement deficiency by **$1,359,791**.

10) The projected 2021 pension settlement loss should be amortized over 20 years rather than being included in its entirety in test period pension cost. This adjustment reduces the Utah revenue requirement deficiency by **$3,342,321**.

11) The Reliability Coordinator expense should be adjusted to reflect the lower current cost of the California Independent System Operator ("CAISO") performing this service compared to the former contractor, PEAK Reliability. This adjustment reduces the Utah revenue requirement deficiency by **$1,360,126**.

12) An error acknowledged by RMP regarding the formula in its adjustment for incremental decommissioning costs associated with the Colstrip plant should be corrected. Correction of this error reduces the Utah revenue requirement deficiency by $**706,532**.

13) RMP's proposed revenue requirement for the Pryor Mountain project should be adjusted so that it is comparable to the avoided cost rate RMP was offering to Wyoming Qualifying Facilities ("QFs") at the time the Pryor Mountain project was developed, which I have identified as being $26.00 per MWh for 20 years, with any Production Tax Credits ("PTCs") and revenues from Renewable Energy Credits ("RECs") retained by the Company. This adjustment reduces the Utah revenue requirement deficiency by [redacted].

14) I present an illustrative revenue requirement adjustment that incorporates a return on equity ("ROE") of 9.50% rather than the 10.20% ROE requested by RMP. My illustrative ROE is based on 9.50% ROE that the Company agreed to in Washington as part of a stipulation dated July 17, 2020 in Docket No. UE 191024, et al., before the Washington Utilities and Transportation Commission ("WUTC"). The Utah revenue requirement reduction from such an adjustment is **$37,260,685** relative to the Company's filed case.

15) The authorized rate of return on common equity applicable to the undepreciated balance of the retired plant (inclusive of associated accumulated deferred income taxes [“ADIT”]) associated with RMP’s wind repowering projects should be reduced by 200 basis points to better balance the benefits from these projects between customers and the Company. This adjustment reduces the Utah revenue requirement deficiency by **$3,145,085** relative to the rate of return on rate base incorporating the illustrative ROE described in my testimony.

16) RMP should be allowed to recover the cost of the Craig 2 Selective Catalytic Reduction (“SCR”) investment in rates but should earn less than a full return on rate base for this project. Specifically, I recommend that the ROE for this project be set equal to the cost of long-term debt, plus a tax gross up. This adjustment reduces the Utah revenue requirement deficiency by **$420,498** relative to the rate of return on rate base incorporating the illustrative ROE described in my testimony.

17) RMP’s proposal to use deferred tax benefits to offset projected Deer Creek Mine recovery royalties should be rejected. Instead, I recommend that customers be credited with two-thirds of these benefits in 2021 and one-third in 2022 through the Schedule 197. This ratio is consistent with apportionment of Schedule 197 credits in 2021 and 2022 proposed by RMP as a rate mitigation measure.

18) RMP’s proposal to include variations in PTC benefits in the Energy Balancing Account (“EBA”) should be rejected.

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 **$80,887,748** relative to RMP’s filing. UAE’s final base revenue requirement results in a **$14,898,712** increase relative to current base rates in Utah. This contrasts with the base rate increase of $**95,786,460** proposed by RMP.

In addition, I recommend that customers be credited with an additional **$3,499,460** in 2021 and **$1,749,730** in 2022 through Schedule 197, consistent with my recommendation to reject RMP’s proposal to offset projected Deer Creek Mine recovery royalties with deferred tax benefits. Since I recommend that this credit be effectuated through Schedule 197, it does not impact the base revenue requirement

Table KCH-1
Summary of UAE Revenue Requirement Adjustments for 2021 Test Period

RMP Requested Increase **$95,786,460**

Summary of Revenue Requirement Impact of UAE Adjustments

	Adjustment	Increase
Pro Forma Capital Additions	(7,120,052)	88,666,408
Retired Wind Plant Balances	(1,943,228)	86,723,181
Prepaid Pension/PRW Asset Reversal	(10,496,736)	76,226,445
Cholla 4 Closure Regulatory Asset Adjustment	(1,107,764)	75,118,681
Non-Labor O&M Inflation Reversal	(3,566,389)	71,552,292
Benefit Expense Error Correction	(708,820)	70,843,472
Wage Increase	(702,798)	70,140,674
Annual Incentive Compensation Expense	[redacted]	[redacted]
Employee Count Reduction	(1,359,791)	[redacted]
Pension Expense - Settlement Loss	(3,342,321)	[redacted]
Reliability Coordinator Expense	(1,360,126)	[redacted]
Colstrip Decommissioning Error Correction	(706,532)	[redacted]
Pryor Mountain Wind Plant Adjustment	[redacted]	[redacted]
Return on Equity *	(37,260,685)	18,464,295
Retired Wind Assets - Allowed Return	(3,145,085)	14,344,161
Craig Unit 2 SCR - Allowed Return	(420,498)	13,923,638
Total UAE Test Period Adjustments	(80,887,748)	

*** Includes illustrative ROE adjustment.**

Revenue Increase reflecting UAE Adjustments **$14,898,712**

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, 2021, which is nearly 20 months beyond the Company's filing date of May 8, 2020. 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."[1] RMP also justified its choice of a 2021 test period by stating that "if the 2021 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."[2]

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. According to RMP's 1st Revised Response to UAE Data Request 3.9, the Company has identified $84.3 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, 2021, or has been canceled.[3] Measured at the end of the test period, i.e., as of December 31, 2021, this corresponds to $140.2 million in gross plant that has been postponed or canceled. In my opinion, 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-2021 plant, as the latter falls outside the bounds of the projected test period.

[1] Rocky Mountain Power's Notice of Intent to File a General Rate Case and Request for Approval of Test Period ("Test Period Application") at 4.
[2] *Id*. at 5.
[3] 2021 13-month average. *See* RMP's 1st Revised Response to UAE Data Request 3.9, Attachment UAE 3.9 1st Revised, Attachment UAE 3.9 1st Revised and "Rev Req Components" tabs, included in UAE Exhibit RR 1.17.

Q. DID THE COMPANY ALSO IDENTIFY PLANT THAT IS NOW EXPECTED TO BE IN SERVICE DURING THE TEST PERIOD, BUT WHICH WAS NOT INCLUDED IN THE COMPANY'S REQUESTED REVENUE REQUIREMENT?

A. Yes. RMP has identified $55.6 million in plant that is now expected to be in service as of December 31, 2021, but which RMP indicates was not included in the Company's requested revenue requirement.[4]

Q. WHAT IS YOUR RECOMMENDED ADJUSTMENT?

A. All post-2021 and canceled plant and associated depreciation expense should be removed from the 2021 revenue requirement. The resulting impact from this adjustment is a reduction of **$7,120,052** to the Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.1.

Q. DOES YOUR ADJUSTMENT INCLUDE THE NEW PLANT THAT IS NOW EXPECTED TO BE IN SERVICE DURING THE TEST PERIOD, BUT WHICH WAS NOT INCLUDED IN THE COMPANY'S REQUESTED REVENUE REQUIREMENT?

A. No. I believe the burden for including this new plant in rate base rests with the Company. I imagine that RMP will have the opportunity to argue for inclusion of this new plant in the revenue requirement in its rebuttal filing when the Company responds to my proposal to exclude the postponed and canceled plant from rate base.

[4] *Id.*

III. RATE BASE ASSOCIATED WITH RETIRED WIND ASSETS

Q. PLEASE EXPLAIN WHY YOU ARE PROPOSING AN ADJUSTMENT FOR RATE BASE ASSOCIATED WITH RETIRED WIND ASSETS.

A. Each of the 11 repowered wind projects approved by the Commission in Docket No. 17-035-39, plus the Leaning Juniper repowering project (together "Repowered Wind Projects"), had a substantial portion of original equipment retired when the wind plants were repowered. RMP proposes to recover the cost of the original investment that it retired, plus a return on that investment, for each of the Repowered Wind Projects. The question I explore here is: what is the appropriate measurement of the retired asset value – upon which RMP will earn a return – in the test period?

Since customers continue to pay the depreciation expense associated with the Repowered Wind Projects' retired assets in rates, even after the assets are retired, one might expect that the rate base associated with the retired assets would continue to decline at the rate at which depreciation expense is currently recovered in rates for those same assets. However, that is not the case if RMP's proposed treatment in the 2018 Depreciation Case[5] is approved.[6] RMP proposes to effectively "freeze" the value of the retired assets on the date each set of wind assets is retired – even though customers continue to pay for the depreciation expense associated with these assets in rates. The *de facto* asset values remain frozen until the rate effective date of this rate case, at which time they begin to depreciate again upon adoption of the new depreciation rates approved in the depreciation docket.

[5] *Application of Rocky Mountain Power for Authority to Change its Depreciation Rates Effective January 1, 2021*, Docket No. 18-035-36.
[6] Although UAE is a signatory to the Stipulation on Depreciation Rate Changes (March 19, 2020) approved by the Commission in its April 20, 2020 Report and Order in Docket No. 18-035-36, this issue is expressly reserved for resolution in Phase II of that docket (Stipulation at ¶ 19).

The problem with RMP's treatment is that it deprives customers of the benefit that would otherwise come from reducing the rate base associated with the retired assets between the time of retirement and the effective date of new rates in this case (presumed to be January 1, 2021). By effectively freezing the value of the retired assets at their respective retirement dates, RMP is able to temporarily collect the depreciation expense on these assets that customers currently pay in rates without crediting the dollars collected against the value of the retired assets. In my view, this treatment unreasonably overstates the rate base associated with the retired assets on the rate effective date.

Q. SINCE THE PROBLEM YOU ARE DISCUSSING DERIVES FROM THE DEPRECIATION CASE, WHY ARE YOU ADDRESSING IT HERE IN THIS GENERAL RATE CASE?

A. I am addressing this issue here to reflect the revenue requirement impact of my recommendation. I am concurrently filing testimony in Phase II of Docket No. 18-035-36 that is consistent with my recommendation on this topic explained herein.

Q. WHAT IS YOUR RECOMMENDED TREATMENT OF THE VALUE OF THE RETIRED WIND ASSETS IN THIS RATE CASE?

A. Rather than effectively freezing the value of these Repowered Wind Projects' assets when each asset is retired until January 1, 2021, the *de facto* "value" of the retired assets should continue to be reduced through that time to reflect the depreciation expense associated with these assets in current rates.[7] This treatment would ensure that customers get the proper

[7] I am not making a similar recommendation for the Foote Creek I project because the existing assets for that project are scheduled for retirement in December 2020, making a similar adjustment unnecessary.

benefit from continuing to pay off these assets between the retirement date and the rate effective date in this case.

Q. HOW WOULD YOUR RECOMMENDATION BE IMPLEMENTED?

A. My recommendation would be implemented by adjusting the accumulated depreciation reserve reflected in RMP's filing by the amount of depreciation expense associated with the retired assets that customers have continued to pay in rates between the time each of the Repowered Wind Projects' assets was retired and January 1, 2021, the presumed rate effective date in this case.

Q. WHY WOULD YOUR ADJUSTMENT BE MADE TO THE ACCUMULATED DEPRECIATION RESERVE?

A. When each of the Repowered Wind Projects' assets was retired, RMP made simultaneous and offsetting adjustments to plant-in-service and the accumulated depreciation reserve. Specifically, plant-in-service was reduced by the gross amount of the retired asset, whereas the depreciation reserve was debited by the same amount (*i.e.*, it was made smaller, providing less of a credit against rate base).[8] This simultaneous accounting adjustment has the effect of keeping rate base unchanged from what it was just prior to the adjustment. However, since the retired assets are no longer in plant in service, RMP's continued recovery of, and on, these costs will be effectuated through the depreciation reserve, which now includes the previously undepreciated net book value of the retired wind assets. Since the depreciation reserve is the vehicle through which RMP will recover the remaining cost of the retired assets, my recommendation can be implemented by adjusting the depreciation

[8] *See* RMP response to UAE Data Request 2.37, included in UAE Exhibit RR 1.17.

reserve. In the alternative, the retired plant could be moved to a regulatory asset and amortized over the same time period RMP proposes for depreciating the remaining balance.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR RETIRED WIND ASSET RATE BASE ADJUSTMENT?

A. The resulting impact from my retired wind asset rate base adjustment is a reduction of **$1,943,228** to the Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.2. This adjustment includes a conforming adjustment to test period depreciation expense to reflect the lower rate base for the retired assets on January 1, 2021 per my recommendation.

IV. INCLUSION OF PREPAID PENSION AND POSTRETIREMENT WELFARE ASSETS IN RATE BASE

Q. WHAT IS RMP PROPOSING WITH RESPECT TO ITS PREPAID PENSION AND OTHER POSTRETIREMENT WELFARE ("PRW") ASSETS?

A. RMP is proposing to include both of these items in rate base.[9] Neither of these items is included in rate base today.

Q. BY WAY OF BACKGROUND, WHAT ARE THE PREPAID PENSION AND PRW ASSETS?

A. The Company's prepaid pension asset represents the amount by which the Company's cumulative contributions to its pension plan have exceeded the cumulative pension cost, measured using Accounting Standards Codification ("ASC") 715. In a given year, ASC

[9] Direct Testimony of Nikki Kobliha, lines 686-818.

715 pension cost, which is the basis for setting RMP's pension expense in a general rate case, differs from cash contributions because pension cost is determined based on accounting guidance while contributions reflect the actual out-of-pocket expenditures in that year. Over the life of a plan, cumulative contributions will equal plan costs, but an asset or liability is recorded to account for the timing differences between cost recognition and cash flow. For circumstances in which cash contributions exceed cost, an asset is recorded (a prepaid pension asset). Conversely, if cost exceeds cash funding, a liability is recorded (an accrued pension liability).

A comparable situation exists for the Company's PRW plan. Historically, in contrast to the prepaid pension asset, the PRW plan has consistently been in an accrued liability position. That is, until recently, cumulative accounting costs for the PRW plan typically exceeded cumulative Company contributions. However, in the 2021 test period, the PRW plan is projected to shift from a regulatory liability to a regulatory asset.

Q. WHAT IS THE AMOUNT OF THE PREPAID PENSION/PRW ASSETS RMP INCLUDES IN RATE BASE IN THE 2021 TEST PERIOD?

A. RMP includes a prepaid pension/PRW asset of $252.3 million in rate base on a Total Company basis, net of ADIT.[10] The amount included in Utah rate base is $110.3 million.

[10] This amount reflects PacifiCorp's prepaid pension asset of $326.557 million plus its other post-retirement prepaid asset of $7.046 million less associated ADIT of $81.268 million. *See* Direct Testimony of Nikki Kobliha, line 707-710 and Exhibit RMP__(SRM-3), pp. 8.13-8.13.1.

Q. HAS THE PREPAID PENSION/PRW ASSET GROWN SINCE THE LAST RATE CASE?

A. Yes. In the test period ending June 30, 2015 used to set rates in the last rate case, the prepaid pension/PRW asset that RMP proposed to include in rate base (net of ADIT) was $162.0 million (Total Company), which translated into a Utah rate base of $68.8 million.[11] As I discussed above, this amount has since grown to $252.3 million (Total Company) as presented by the Company on a Total Company basis.

Q. WHAT ACCOUNTS FOR THIS GROWTH IN THE PREPAID PENSION/PRW ASSET?

A. As I discussed above, the prepaid pension/PRW asset is equal to the cumulative plan contributions made by the Company in excess of cumulative accounting cost; therefore, in a technical sense, growth in the prepaid asset occurs when the first component grows more than the second component. However, we need to be careful not to interpret growth in the prepaid asset as being driven necessarily by Company contributions that are greater than what customers contribute to the plans in rates.

Q. PLEASE EXPLAIN.

A. To see this point, we can focus on the prepaid pension asset, which is orders of magnitude larger than the PRW asset. Once pension expense is set in rates, the amount of annual recovery from customers does not change, even though accounting pension cost does change from year to year. As it turns out, accounting pension cost has declined significantly since rates were last set. The test period in the last general rate case was the

[11] *See* Docket No. 13-035-184, Direct Testimony of Kevin C. Higgins (UAE Exhibit RR 1.0), lines 962-968. This was comprised of a prepaid pension asset equal to $312.2 million and an "other post-retirement" liability of $31.2 million (for a net prepaid balance of $281.0 million), less net ADIT of $119.0 million.

12 months ended June 30, 2015, and the projected Company-wide pension cost for that year, as updated during the case, was $10.5 million.[12] While the revenue requirement in that case was settled, Utah's share of the test period pension cost best represents the pension cost (pension expense plus capitalized pension cost) that is in Utah rates today. By 2017, Total Company pension cost had fallen to negative $12.4 million. And in 2019, pension cost was negative $14.5 million.[13] In other words, accounting pension cost since the last general rate case has been much lower than the amount being recovered in Utah rates. And when pension cost is negative, as it was in 2017 and 2019, the prepaid pension asset increases automatically (*i.e.*, by definition) even if Company contributions to the plan are zero, as has been the case since January 2018.[14] The upshot is that the Company's prepaid pension asset has increased even as customers pay an amount for pension cost in rates that is well above what actual pension cost turned out to be. The prepaid pension asset has grown because it is calculated using the annual accounting cost as it changes from year to year – not the amount of accounting cost that happens to be in rates as a result of the last rate case – and accounting cost has declined significantly.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING RMP'S PROPOSAL TO INCLUDE THE PREPAID PENSION ASSET IN RATE BASE?

A. I recommend that RMP's proposal be rejected. Allowing this change would result in an unreasonable transfer of risk to customers, even though RMP argues otherwise.

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[12] Docket No. 13-035-184, Exhibit RMP__(SRM-2R), p. 12.3.6.
[13] *See* RMP response to UAE Data Request 2.1, Attachment UAE 2.1-2 CONF, included in Confidential UAE Exhibit RR 1.18. Note that RMP has confirmed that the 2017 and 2019 pension cost reported here in my testimony are not confidential. The most likely cause of negative pension cost is an expected return on plan assets that is greater than the interest cost, service cost, and amortizations.
[14] See RMP response to UAE Data Request 7.1, included in UAE Exhibit RR 1.17.

Q. PLEASE EXPLAIN.

A. As I just explained above, RMP's prepaid pension asset has been growing, caused largely by negative pension accounting costs, which causes the prepaid pension asset to increase even when Company contributions to the plan are zero (while customers continue to pay rates that assume positive pension costs). While the concept of negative pension accounting costs might seem at first to be counter-intuitive, they can occur when the expected return on plan assets is greater than the interest cost, service cost, and amortizations. Put another way, the prepaid pension asset can grow, even when corporate contributions are zero, due to robust expected returns on plan assets. If the prepaid pension asset is included in rate base, customers would be required to pay the Company a return on the growth in the asset due to higher expected returns in the market. I believe this is an unreasonable shift of risk to customers.

More broadly, the issue at the heart of RMP's proposal is one of timing differences – specifically what happens during periods in which cumulative contributions exceed cumulative accounting cost. Utah ratemaking practice provides for recovery of prudently incurred pension cost calculated in accordance with ASC 715. Over the life of the pension plan, the cumulative accounting cost will equal the total of the Company's contributions. So, the issue is not whether Utah ratepayers fully fund Utah's share of pension costs – indeed, Utah customers fully fund these costs.[15] Rather, the issue is: who should bear the risk of timing differences with respect to the relationship between cumulative contributions and cumulative expense, the Company or customers? I believe the responsibility to

[15] Of course, rates are not reset every year, so pension expense is not tracked or reimbursed dollar for dollar: that is not how ratemaking is done. Moreover, as I discussed above, in 2017 and 2019 the Company's pension expense was actually negative, but rates to customers were not reduced to reflect this negative expense.

manage the timing differences appropriately rests with the Company, and so should the risk. In Utah, utility management is expected to cope with normal business risks and the operation of economic forces.[16] The Commission should not allow RMP to shift this burden to customers

Q. HAS IT ALWAYS BEEN THE CASE THAT THE TIMING DIFFERENCES WERE CHARACTERIZED BY CUMULATIVE CONTRIBUTIONS EXCEEDING CUMULATIVE ACCOUNTING COSTS?

A. No. As I explained in Docket No. 13-035-184, from at least 1998 through 2005, cumulative pension accounting costs exceeded cumulative pension contributions; as such, the Company was in an accrued pension liability position during those years.[17] At no time during that period did RMP propose to *reduce* rate base to the benefit of customers to reflect the Company's accrued liability position.

Q. HAVE ANY OTHER PACIFICORP JURISDICTIONS REJECTED THE COMPANY'S REQUEST TO EARN A RETURN ON ITS PREPAID PENSION ASSET?

A. Yes. The Public Utility Commission of Oregon devoted an entire docket to this question before determining that prepaid pension assets should not be included in rate base.[18]

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[16] *See*, for example, *In the Matter of the Investigation into the Reasonableness of Rates and Charges of PacifiCorp, dba Utah Power & Light Company*, Docket No. 97-035-01, Report and Order (March 4, 1999) at 47-48.
[17] Docket No. 13-035-184, Direct Testimony of Kevin C. Higgins (UAE Exhibit RR 1.0), lines 984-995.
[18] *In the Matter of Public Utility Commission of Oregon Investigation into Treatment of Pension Costs in Utility Rates*, OR Pub. Utility Commission, Docket No. UM 1633, Order No. 15-226, (Aug. 3, 2015).

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR RECOMMENDATION?

A. The resulting impact from my adjustment is a **$10,496,736** reduction to Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.3.

Q. YOUR RECOMMENDATION TO REJECT THE COMPANY'S PROPOSAL NOTWITHSTANDING, DO YOU HAVE ANY FURTHER RECOMMENDATIONS IN THE EVENT THE COMMISSION ALLOWS THE COMPANY TO INCLUDE THE PREPAID ASSETS IN RATE BASE?

A. Yes. Although I believe the Company's proposal should be rejected in its entirety, in the event the Commission approves some version of RMP's proposal, I would recommend that the Commission set the allowed return on the Company's prepaid assets equal to the Expected Return on Assets ("EROA") for its pension and PRW plans.

Q. PLEASE EXPLAIN THIS POINT.

A. The 2021 EROA for RMP's pension plan is 6.0%.[19] In contrast, the cost to customers of paying RMP its pre-tax rate of return on its prepaid pension asset is 9.525% at RMP's proposed rate of return.[20] In a ratemaking sense, with the prepaid pension asset in rate base, RMP is requesting that customers, who are ultimately funding the plan, to compensate the Company at 9.525% so that the proceeds can be invested in its pension plan at an expected return of 6.0%. Even though the funds invested at 6.0% are expected to produce future returns, the carrying cost is clearly too high: paying a return of 9.525% on proceeds invested at 6.0% obviously is not a good proposition for customers.

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[19] *See* RMP response to UAE Data Request 2.2.j, Attachment UAE 2.2(j) CONF, included in Confidential UAE Exhibit RR 1.18.
[20] Derived from UT GRC JAM - DEC 2021 Test Period, "Report" and "Results" tabs.

Indeed, if the prepaid pension asset were to be included in rate base, it would be unreasonable for customers to pay a carrying charge to RMP that is any greater than the EROA for RMP's pension plan. The same is true for the Company's PRW plan. Therefore, if the Commission allows the prepaid assets in rate base, I recommend that the Commission set the return on the prepaid pension asset equal to the EROA for RMP's pension plan, without a tax gross-up, and the return on the prepaid PRW asset at the 2021 EROA for the PRW plan, which is 3.7%,[21] also without a tax gross-up.

Q. HAVE OTHER COMMISSIONS ADOPTED SIMILAR PROVISIONS THAT REDUCED THE RATE OF RETURN ON PREPAID PENSION ASSETS?

A. Yes. In the most recent Public Service Company of Colorado ("PSCo") general rate case proceeding, the Colorado Public Utilities Commission set the return on PSCo's prepaid pension asset equal to PSCo's cost of debt, stating:

> [W]e conclude that absent a finding that it was improper to maintain the prepaid asset for a certain period of time, allowing a return on the prepayment amounts is warranted. We therefore adopt [Colorado Energy Consumers'] proposal in this Proceeding to set the return on the Current Prepaid Pension Asset at the Company's cost of long-term debt established by Decision No. C20-0096. As Mr. Higgins points out in his answer testimony, asking ratepayers to give Public Service a 9.57 percent return on the prepaid asset so that the Company can invest the funds in the asset at a projected return to ratepayers of 6.84 percent is a poor deal for ratepayers. We agree with Mr. Higgins' suggestion to set the Company's return on the prepaid pension asset equal to the cost of long term debt. . . . And, it balances the Company's right to earn a return on the capital it invests with the ratepayers' right to just and reasonable rates.[22]

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[21] *See* RMP response to UAE Data Request 2.3.i, Attachment UAE 2.3(i) CONF, included in Confidential UAE Exhibit RR 1.18.

[22] *In the Matter of Advice Letter No. 1797 Filed by Public Service Company of Colorado to Reset the Currently Effective General Rate Schedule Adjustment (GRSA) as Applied to Base Rates for All Electric Rate Schedules as Well as Implement a Base Rate KWh Charge, General Rate Schedule Adjustment-Energy (GRSA-E) to Become Effective June 20, 2019*, Colo. Pub. Utilities Comm'n, Proceeding No.19AL-0268E, *Decision Addressing Applications for Rehearing, Reargument, or Reconsideration; Addressing Related Motions; And Conditionally Requiring a Compliance Tariff Filing*, ¶79 (May 13, 2020) (internal citations omitted).

Q. HAVE YOU CALCULATED THE REVENUE REQUIREMENT IMPACT OF YOUR ALTERNATIVE ADJUSTMENT TO THE PREPAID PENSION/PRW RETURN?

A. Yes. The resulting reduction to RMP's proposed Utah revenue requirement deficiency is approximately **$3,819,195** for my alternative prepaid pension asset return adjustment, calculated relative to the rate of return requested by RMP. If the Commission approves RMP's proposal but adopts my alternative prepaid PRW asset return adjustment, the resulting reduction to RMP's proposed Utah revenue requirement deficiency is approximately **$155,083**, also calculated relative to the rate of return requested by RMP. Because these calculations are alternatives to my primary recommendation, they are not included in Table KCH-1.

V. <u>CHOLLA UNIT 4</u>

Q. WHAT RATEMAKING TREATMENT IS RMP PROPOSING WITH RESPECT TO ITS CHOLLA UNIT 4 PLANT?

A. RMP has announced that Cholla Unit 4 will be retired by the end of 2020. As described by RMP witness Joelle R. Steward, the Company is proposing to use the current balance in the Sustainable Transportation and Energy Plan ("STEP") regulatory liability account, which is $179.6 million, to buy down the undepreciated plant balance of Cholla Unit 4, as well as Craig Unit 1 and a portion of Craig Unit 2.[23] Of this amount, $145.9 million relates to Cholla Unit 4. The proposed buy-down is consistent with the terms of the settlement

[23] Direct Testimony of Joelle Steward, lines 307-311.

agreement in the Tax Cuts and Jobs Act ("TCJA") case, Docket No. 17-035-69, which was approved by the Commission.

In addition, RMP is removing Cholla Unit 4 depreciation expense from rates and proposes to create a regulatory asset to recover closure and incremental decommissioning costs. There are three categories of closure costs included in the proposed regulatory asset: CWIP ($1.8 million), Materials and Supplies ($6.1 million), and Liquidated Damages ($19.6 million), for a total of $27,562,070 on a Total Company basis.

Q. DO YOU HAVE ANY RECOMMENDED ADJUSTMENTS TO THE COMPANY'S PROPOSED TREATMENT OF CHOLLA UNIT 4 COSTS?

A. Yes. I recommend that CWIP and materials and supplies be excluded from recovery in the regulatory asset. These items were never used and useful and should not be passed on to customers. RMP should be permitted to sell off the unneeded materials and supplies and retain the proceeds. Taking a big picture view, use of the STEP funds to buy down the Cholla Unit 4 plant balance relieves the Company of the burden and risk associated with the unrecovered plant balances for a plant that is being retired early and will no longer be providing service to customers. In my opinion, excluding recovery of the CWIP and unused materials and supplies ensures that the overall package is just and reasonable to both customers and the Company.

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

A. The resulting impact from my adjustment is a **$1,107,764** reduction to Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.4.

VI. INFLATION IN NON-LABOR O&M EXPENSE

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 2019 through December 2021.[24]

To apply this cost escalator, RMP starts with its actual non-labor O&M expense for the base period, January to December 2019. RMP then applies a series of escalation factors to its base period cost for its materials and services using indices provided by IHS Markit (formerly IHS Global Insight).

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

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. 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.

[24] *See* Exhibit RMP_(SRM-3), p. 4.10, O&M Expense Escalation.

Q. WHAT IS YOUR SECOND MAJOR CONCERN?

A. A related, but distinct, concern involves the building of this "cost cushion" into the Company's test period costs. Allowing this type of systemic uplift in rates goes well beyond the basic rationale advanced by advocates for using a projected test period, which is to ameliorate the effect of regulatory lag on the recovery of investment in new plant.

Q. PLEASE EXPLAIN.

A. Prior to 2008, the Commission had a longstanding practice of requiring utilities to use historical test periods in setting rates, preferring the certainty of information that comes with using actual expenses, revenue, and investment as the basis for setting rates. Starting in 2008,[25] the Commission started to allow utilities to use projected test periods in setting rates. The primary justification for this practice is to allow a utility with expanding rate base the ability to avoid regulatory lag; that is, the use of a projected test period is intended to provide a utility a better opportunity to recover its investment cost than might occur with an historical test period. Since first allowing projected test periods in 2008, utility test periods in Utah have reached increasingly further into the future; in the instant case, RMP's projected test period extends nearly 20 months beyond the Company's filing date.

In this case, RMP is attempting to go well beyond simply aligning the test period with its projected 2021 investment to mitigate regulatory lag; the Company is also attempting to gain an additional benefit by inflating its baseline costs by applying an indexed inflation factor through the end of 2021. Yet the use of a projected test period is

[25] The Commission departed from its previous practice of requiring historical test periods in Docket No. 07-035-93, in which the Commission approved a projected test period extending approximately 12½ months beyond the utility's filing date.

the Company's *choice*: it is not required to do so. RMP should not be rewarded with a windfall mark-up of its baseline costs through an inflation adjustment simply by virtue of its test period selection. The Commission should not allow the use of a future test period to become a vehicle for utility recovery of such synthetic costs. Rather, RMP should be expected to strive to improve its O&M efficiency on a continuous basis, and thereby lessen the net impact of inflation on its O&M costs. It is not reasonable to simply gross up the Company's base period costs by an index factor and pass these inflated costs on to customers, thus virtually assuring utility rate inflation.

Q. IS THERE EVIDENCE THAT RMP'S INFLATION FACTORS ARE OVERSTATED IN THIS CASE?

A. Yes. In response to OCS Data Request 5.1,[26] RMP provided more up-to-date inflation projections, many categories of which now reflect cost *deflation*. Substitution of the updated projections for the as-filed inflation projections would actually result in a Total Company O&M expense *decrease* of $5.57 million, rather than an increase of $10.09 million as proposed by RMP in its filing.[27]

Q. ARE YOU RECOMMENDING THAT THE UPDATED INFLATION AND DEFLATION PROJECTIONS BE USED TO ADJUST O&M EXPENSE IN THIS CASE?

A. No, even though doing so would result in a greater reduction to the revenue requirement than simply eliminating the inflation adjustment entirely. Rather, I am maintaining my longstanding position before this Commission and others that including the index cost

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[26] Included in UAE Exhibit RR 1.17.
[27] The $10.09 million increase is shown in Exhibit RMP___(SRM-3), p. 4.10-4.10.4. The decrease is calculated by replacing the initial inflation projections with the updated projections.

escalators in the non-labor O&M revenue requirement for projected test periods is unreasonable. Therefore, my recommendation is to remove the inflation escalators proposed by RMP without substituting the updated inflation and deflation projections in their stead.

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 **$3,566,389** reduction to the Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.5.

VII. <u>CORRECTION OF BENEFITS EXPENSE ERROR</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO CORRECT AN ERROR TO BENEFITS EXPENSE.

A. RMP has acknowledged an error in the calculation of its Post-Retirement Benefits expense, which mistakenly included a United Mine Workers of America transfer cost.[28] I have corrected this error in the UAE-recommended revenue requirement.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR CORRECTION OF THIS ERROR?

A. The impact of correcting this error is a **$708,820** reduction to the Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.6.

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[28] RMP response to UAE Data Request 5.5, Confidential Attachment UAE 5.5, included in Confidential UAE Exhibit RR 1.18.

VIII. WAGE INCREASE ADJUSTMENT

Q. PLEASE EXPLAIN THE BASIS FOR YOUR WAGE INCREASE ADJUSTMENT.

A. RMP adjusts its labor expenses to include wage increases that are projected to occur through December 31, 2021. In so doing, the Company annualizes these wage increases, calculating its adjustment as though the wage increases were in effect for the entire projected test period, when in fact, the wage increases are projected to occur at various points during the test period.

RMP's annualization adjustment would arguably be more appropriate for a historical test period. However, it is not appropriate for a fully projected test period, as it will overstate the wage levels in the test period and the rate effective period by including in rates on January 1, 2021 projected wage increases that are not anticipated to be fully completed until December 31, 2021. Instead, I recommend a pro forma adjustment that will reflect the projected wage levels that will exist during the 12 months ended December 31, 2021, rather than the wage levels at year-end 2021.

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

A. The resulting impact from my wage adjustment is a **$702,798** reduction to the Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.7.

IX. ANNUAL INCENTIVE COMPENSATION FOR EMPLOYEES

Q. PLEASE DESCRIBE RMP'S AIP.

A. RMP provides an AIP for its eligible employees. The AIP determines cash awards based on a combination of Company, department, and individual performance.[29]

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.[30]

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 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 RMP meets or exceeds financial targets.

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

A. Yes. The Commission has consistently required that incentive compensation that is tied to financial performance be funded by shareholders. The foundations of the Commission's

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[29] RMP response to UAE Data Request 5.1, Attachment Confidential Attachment UAE 5.1 (PacifiCorp 2019 AIP CONF), included in Confidential UAE Exhibit RR 1.18.
[30] Exhibit RMP__(SRM-3), confidential p. 4.2.6.

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 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 RMP's response to discovery,[31] the 2019 AIP included PacifiCorp goals tied to [redacted] and [redacted], weighted at approximately [redacted] and [redacted], respectively. I recommend that the AIP expense included in rates exclude these components. My adjustment reduces RMP's Utah revenue requirement deficiency by approximately [redacted] relative to the Company's filed case. This adjustment is shown in Confidential UAE Exhibit RR 1.8.

X. <u>EMPLOYEE COUNT REDUCTION</u>

Q. PLEASE DESCRIBE THE BASIS FOR YOUR ADJUSTMENT TO RMP'S PROPOSED WAGE AND BENEFITS EXPENSES TO ACCOUNT FOR A REDUCTION TO EMPLOYEE COUNT.

A. RMP's proposed test period labor expenses are based on labor expenses during the base period, escalated for known and measurable changes. Thus, RMP's proposed test period labor expenses are effectively based on the <u>average</u> FTE employee count that existed during the base period (13 months ended December 31, 2019), which was an average of 4,927.3 FTE employees. [32]

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[31] RMP response to UAE Data Request 5.2, Confidential Attachment UAE 5.2, PacifiCorp 2019 Scorecard CONF, included in Confidential UAE Exhibit RR 1.18.
[32] *See* RMP response to UAE Data Request 2.5, Attachment UAE 2.5, included in UAE Exhibit RR 1.17.

However, as shown in RMP's response to UAE Data Request 2.5, the Company's FTE count declined significantly throughout and subsequent to the base period. The average FTE count for the 13 months ended May 31, 2020 was 35.2 FTEs less than the average FTE count that existed during the base period.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE FTE COUNT FOR SETTING RMP'S WAGE AND BENEFITS EXPENSE IN THIS CASE?

A. I recommend that test period wage and benefits expense be based on the average FTE level for the 13 months ended May 31, 2020,[33] which better reflects the Company's likely employment level going forward than RMP's initial filing. Accordingly, I have reduced wage and benefits expense to account for a reduction of 35.2 FTEs. I have derived this adjustment by reducing the adjusted wage and benefits expense to reflect the 0.72% reduction in FTE count, for cost categories likely to be affected by a change in employee count.

Q. WHY DO YOU BELIEVE IT IS APPROPRIATE TO BASE RMP'S LABOR EXPENSES ON THE AVERAGE FTE COUNT FOR THE YEAR ENDED MAY 2020?

A. The Company's FTE count has declined materially since the base period in the last rate case (year-ended June 2013), during which the Company employed an average of 5,473.2 FTEs.[34] The continued steady decline since January 2017 is presented in Table KCH-2, below. Since the Company is proposing a 2021 forecasted test period, I believe it is

[33] The May 2020 FTE level is the most recent information RMP provided to me at the time my testimony is filed.
[34] Based on the average actual FTE count for the 13 months ended June 2013. *See* Docket No. 13-035-184, Filing Requirement Attachment R746-700-22.D.23.

preferable to use more recent information than the base period employee count for setting the going-forward test period wage and benefits expense.

Table KCH-2
PacifiCorp FTEs
January 2017 – May 2020[35]

Month-End	FTE Count		Month-End	FTE Count
Jan-2017	5,060.5		Oct-2018	5,023.5
Feb-2017	5,043.5		Nov-2018	5,004.5
Mar-2017	5,061.0		Dec-2018	4,988.0
Apr-2017	5,035.5		Jan-2019	4,994.5
May-2017	5,041.5		Feb-2019	4,999.5
Jun-2017	5,030.5		Mar-2019	4,963.5
Jul-2017	5,028.5		Apr-2019	4,964.0
Aug-2017	5,021.0		May-2019	4,936.5
Sep-2017	4,991.5		Jun-2019	4,919.5
Oct-2017	5,007.0		Jul-2019	4,886.0
Nov-2017	5,017.5		Aug-2019	4,868.0
Dec-2017	5,019.5		Sep-2019	4,866.0
Jan-2018	5,024.5		Oct-2019	4,872.5
Feb-2018	5,047.0		Nov-2019	4,905.5
Mar-2018	5,022.5		Dec-2019	4,891.5
Apr-2018	5,060.5		Jan-2020	4,895.0
May-2018	5,052.5		Feb-2020	4,884.5
Jun-2018	5,039.5		Mar-2020	4,889.5
Jul-2018	5,047.5		Apr-2020	4,896.0
Aug-2018	5,017.5		May-2020	4,886.5
Sep-2018	5,000.0			

Q. IN RECOMMENDING YOUR ADJUSTMENT, ARE YOU ADVOCATING THAT A PARTICULAR NUMBER OF EMPLOYEES IS APPROPRIATE AT PACIFICORP?

A. No. My adjustment is only intended to reflect the most accurate employment level for the purpose of setting rates. I am not advocating that there be a certain number of employees,

[35] Data Source: RMP response to UAE Data Request 2.5, Attachment UAE 2.5, included in UAE Exhibit RR 1.17.

nor am I suggesting that the Commission "micro-manage" the Company. It is up to RMP to manage its employment level to operate efficiently and safely. My adjustment is simply intended to compensate the Company for a realistic level of payroll expense, and not have customers paying rates based on the labor costs for non-existent employees.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR EMPLOYEE COUNT ADJUSTMENT?

A. The resulting impact from my employee count adjustment is a **$1,359,791** reduction to the Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.9.

XI. PENSION EXPENSE – SETTLEMENT LOSS

Q. WHAT HAS RMP PROPOSED REGARDING THE TREATMENT OF SETTLEMENT LOSSES IN PENSION EXPENSE?

A. As explained by RMP witness Nikki L. Kobliha, RMP is proposing an adjustment to pension cost to include a projected 2021 settlement loss of $11.9 million (Total Company) in the test period. RMP is proposing to include $7.9 million of this forecasted settlement loss in pension expense in this case and capitalize the remaining balance.

Q. WHAT ARE SETTLEMENT LOSSES IN THE CONTEXT OF PENSION COST?

A. Under certain circumstances, curtailments and/or settlements are recognized in ASC 715 pension cost, which is the basis for setting RMP's pension expense in a general rate case. A curtailment is an event that significantly reduces the expected years of future service of present employees or eliminates, for a significant number of employees, the accrual of defined benefits for future services. A settlement is an irrevocable action that relieves the employer of primary responsibility for a benefit obligation, and eliminates significant risks related to the obligation and the assets used to effect the settlement. For example, a settlement occurs when the employer provides plan participants with lump-sum cash payments in exchange for their rights to receive specified benefits.

Q. WHEN MUST AN EMPLOYER RECOGNIZE GAINS OR LOSSES IN EARNINGS AS THE RESULT OF SETTLEMENTS?

A. According to ASC 715-30-35-82, if the cost of all settlements in a year exceeds the sum of the service cost and interest cost components of net periodic pension cost (the threshold amount), the employer must recognize a pro rata portion of previously unrecognized gains or losses in earnings.[36] RMP is forecasting such an event in 2021 and projects that it will result in a settlement loss of $11.9 million.

Q. WHAT IS YOUR RESPONSE TO RMP'S PROPOSAL TO INCLUDE THE FULL PROJECTED 2021 SETTLEMENT LOSS IN TEST PERIOD PENSION COST?

A. I recommend a different approach. It could reasonably be argued that a projected settlement loss is too speculative to include in a projected test period; similarly, it could be reasoned that a single year's settlement loss does not reasonably represent ongoing annual pension cost for ratemaking. Weighing against these arguments is RMP's contention that settlement losses are likely to become more commonplace in a low-interest rate environment.

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[36] Unrecognized gains and losses represent the cumulative adjustments to the value of pension plan assets and liabilities that have not yet been reflected in earnings through the net periodic pension cost. In any given year, actual experience will generally differ from the long-term assumptions used to set the net periodic pension cost. For example, the actual return on plan assets may be lower than the expected long-term return included in the net periodic pension cost, resulting in a loss. Employers, including utilities, are not required to immediately recognize these changes to the value of the pension plan assets or liabilities in net periodic pension cost. Instead, such gains or losses can be reflected as increases or decreases to "other comprehensive income," which is excluded from net income. It is possible that, over time, gains and losses may offset each other, but a portion of the net gain or loss is required to be amortized (*i.e.*, recognized in earnings) if a "corridor" of materiality is exceeded. The corridor rule was first established in Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards No. 87 (Dec. 1985).

Taking all of this into account, my recommendation does not challenge recovery of RMP's forecasted settlement loss, but instead I recommend that the recovery of this cost be amortized over 20 years rather than being included in its entirety in annual pension cost in this case. I recommend a 20-year amortization because 20 years is the approximate remaining life expectancy for pension plan participants as of December 31, 2020, which represents the period over which unrecognized losses are amortized absent a settlement event.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR SETTLEMENT LOSS ADJUSTMENT?

A. The resulting impact from my settlement loss adjustment is a **$3,342,321** reduction to the Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.10.

XII. <u>RELIABILITY COORDINATOR</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR RELIABILITY COORDINATOR.

A. RMP is assessed a share of costs to pay for Reliability Coordinator services in the Western Interconnection. In the base period, this service was performed by a firm called PEAK Reliability. However, PEAK Reliability has since been replaced by the CAISO at a lower cost. But in developing its requested revenue requirement, RMP used the PEAK Reliability base period costs, not the lower CAISO costs. I recommend that the expense for this service be adjusted to reflect the lower current cost of CAISO performing the Reliability Coordinator service. For context, the historical costs of RMP's share of Reliability Coordinator service is shown in Table KCH-3 below.

Table KCH-3
Reliability Coordinator Expense[37]
2015-2020

Year	Vendor	Amount	Timeframe
2015	PEAK Reliability	$3,635,241	1/1/15 - 12/31/15
2016	PEAK Reliability	$3,899,622	1/1/16 - 12/31/16
2017	PEAK Reliability	$3,873,262	1/1/17 - 12/31/17
2018	PEAK Reliability	$3,893,221	1/1/18 - 12/31/18
2019	PEAK Reliability	$5,059,884	1/1/19 - 12/31/19
2020	CAISO	$2,307,557	1/1/20 - 12/31/20
GRC Base Period	PEAK Reliability	$5,059,884	1/1/2019 - 12/31/19

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR RELIABILITY COORDINATOR ADJUSTMENT?

A. The resulting impact from my Reliability Coordinator adjustment is a **$1,360,126** reduction to the Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.11.

XIII. COLSTRIP DEPRECIATION EXPENSE CORRECTION

Q. PLEASE DESCRIBE THE COLSTRIP DEPRECIATION EXPENSE CORRECTION.

A. In preparing its response to DPU Data Request 4.4,[38] relating to incremental decommissioning expense, RMP discovered a formula error that caused the Colstrip depreciation expense to be overstated. The adjustment corrects that error as identified by the Company.

[37] RMP response to UAE Data Request 2.44 included in UAE Exhibit RR 1.17.
[38] Included in Confidential UAE Exhibit RR 1.18.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF THIS CORRECTION?

A. This correction reduces Utah revenue requirement deficiency by **$706,532**. This adjustment is shown in UAE Exhibit RR 1.12.

XIV. <u>PRYOR MOUNTAIN PROJECT</u>

Q. BRIEFLY DESCRIBE THE PRYOR MOUNTAIN PROJECT.

A. Pryor Mountain is a 240 MW wind project located in Carbon County, Montana that will bring power into the PacifiCorp system via Wyoming. As described by RMP witness Robert Van Engelenhoven, the acquisition, development, and implementation of the Pryor Mountain project was identified and evolved over a compressed timeline between October 2018 and September 30, 2019, by which time final terms on all material agreements were completed.[39] Mr. Van Engelenhoven testifies that the project also allows the Company to meet a specific retail customer's need for incremental RECs, which the customer, Vitesse LLC, has agreed to purchase pursuant to PacifiCorp's Oregon Schedule 272 - Renewable Energy Rider Optional Bulk Purchase Option. RMP proposes that Wyoming's share of the REC revenues be credited to customers through Schedule 98.[40] The Pryor Mountain wind project cost forecast included in this case is approximately [redacted] million.[41]

Q. DOES RMP PRESENT AN ECONOMIC ANALYSIS OF THE PRYOR MOUNTAIN PROJECT?

A. Yes. An economic analysis is presented by RMP witness Rick T. Link in his Direct Testimony.

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[39] Direct Testimony of Robert Van Engelenhoven, lines 64-68.
[40] Direct Testimony of Joelle R. Steward, lines 254-258.
[41] Direct Testimony of Robert Van Engelenhoven, lines 74-75.

Q. WHAT DOES MR. LINK'S ECONOMIC ANALYSIS SHOW?

A. Mr. Link's analysis indicates a net benefit to customers from the Pryor Mountain project on a Total Company basis of between $69 million and $82 million under a Medium Natural Gas/Medium CO_2 ("MM") scenario, which assumes a carbon tax (or equivalent) is adopted in 2025.[42] Under a Low Natural Gas/Zero CO_2 ("LN") scenario, the projected net benefits decline sharply, ranging from a net *cost* of $1 million to a net benefit of $7 million.[43]

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING RMP'S ECONOMIC ANALYSIS?

A. Yes. RMP's economic analysis of Pryor Mountain includes a substantial terminal value of [redacted] for the project at the conclusion of its projected life in 2050. This large terminal value is added as a benefit to customers in RMP's calculation. The effects of this terminal value on the nominal revenue requirement can be seen in Figure 4 at line 316 of Mr. Link's Direct Testimony for the year 2050. I consider the large assumed benefits in this terminal value forecasted some thirty years hence to be highly speculative. While this speculative benefit is watered down by many years of discounting as part of the Present Value Revenue Requirement ("PVRR") analysis, it still has a material impact on the final result: when the terminal value is removed, the projected net benefits are reduced by [redacted] million for all scenarios.[44] By itself, this eliminates any positive benefit in the LN scenario through 2050.

Q. WHAT WILL CUSTOMERS PAY IN RATES FOR THE PRYOR MOUNTAIN PROJECT IF RMP'S REVENUE REQUIREMENT REQUEST IS APPROVED?

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[42] Direct Testimony of Rick T. Link, lines 292-296.
[43] *Id.* at lines 296-298.
[44] This calculation is performed in a Confidential UAE workpaper.

A. The annual nominal revenue requirement for the Pryor Mountain project (using Mr. Link's weighted average cost of capital ["WACC"] assumptions) is presented in Confidential UAE Exhibit RR 1.13, page 4. The 2021 revenue requirement using Mr. Link's assumptions is [redacted]/MWh, after crediting the PTCs and REC revenues to customers. The levelized revenue requirement for the first 20 years of operation is [redacted]/MWh, also net of PTCs and REC revenues.

Q. DO YOU BELIEVE IT IS REASONABLE FOR UTAH CUSTOMERS TO PAY THIS LEVEL OF COST FOR THE PRYOR MOUNTAIN PROJECT?

A. No, I do not. While I support the development of cost-effective wind projects, it is critical that customers only pay costs that are reasonable and prudent. In this instance, the cost of this Company-developed project has turned out to be considerably more expensive than the avoided cost pricing that RMP was calculating for Wyoming wind QFs at the time this project was developed. This is particularly concerning because RMP has steadfastly maintained that it could provide customers lower cost and lower risk wind-generated power by developing Company-owned wind projects rather than purchasing wind-generated power from QFs.

Q. PLEASE EXPLAIN.

A. I participated in RMP's 2018 QF case in Wyoming,[45] which was conducted during the same general time frame that the Pryor Mountain project was being acquired by RMP. By way of brief background, QFs are independent power facilities that are entitled by Federal law to sell their power to regulated utilities at the utility's "avoided cost" pursuant to the

[45] *In the Matter of the Application of Rocky Mountain Power for A Modification of Avoided Cost Methodology and Reduced Contract Term of PURPA Power Purchase Agreements*, Wyoming Docket No. 20000-545-ET-18 (Record No. 15133).

Public Utilities Regulatory Policies Act ("PURPA"). The methodology for determining avoided cost rates is set by each state's utility regulatory commission. In the 2018 Wyoming QF case, RMP asked the Wyoming Public Service Commission to reduce the contract term for QFs selling power pursuant to the Company's Wyoming Schedules 37 and 38 from 20 years to just seven years, arguing, among other things, that 20-year QF contracts expose the Company's customers to "significant risk" because QFs are tied to resources that do not go through the "rigorous planning process" of the Integrated Resource Plan ("IRP").[46] RMP also argued that PURPA's requirement that the Company purchase all of the QF's output at avoided cost prices can lead to QFs having significantly higher operational, price, and credit risks for the Company's customers compared to resource decisions that are guided by the Company's IRP and procured via competitive solicitations.[47] In its Order, the Wyoming Public Service Commission rejected RMP's request, but reduced the maximum fixed-price contract term from 20 to 15 years.[48] Previously, RMP had requested that this Commission reduce the maximum fixed-price contract term for QFs from 20 years to three years; this Commission also rejected that request but similarly reduced the maximum fixed-price contract term from 20 to 15 years.[49]

At the time the 2018 Wyoming QF case was conducted, the indicative levelized avoided costs prepared by RMP for eight Wyoming wind QFs was in the vicinity of

[46] *In the Matter of the Application of Rocky Mountain Power For A Modification of Avoided Cost Methodology and Reduced Contract Term of PURPA Power Purchase Agreements*, Wyoming Docket No. 20000-545-ET-18 (Record No. 15133), Direct Testimony of Mark P. Tourangeau, pp. 2-4.
[47] *Id.* at p. 12. RMP has made similar representations in Utah. *See* Docket No. 15-035-53, Direct Testimony of Paul Clements, lines 560-596.
[48] *In the Matter of the Application of Rocky Mountain Power For A Modification of Avoided Cost Methodology and Reduced Contract Term of PURPA Power Purchase Agreements*, Wyoming Docket No. 20000-545-ET-18 (Record No. 15133), Memorandum, Opinion, Findings of Fact, Decision and Order, ¶ 27 (June 23, 2020).
[49] Docket No. 15-035-53, Order issued January 7, 2016 at 19.

$26.00/MWh for 20-year contracts, according to discovery provided by RMP in that case.[50] In contrast, the 20-year levelized revenue requirement for the Pryor Mountain project has turned out to be [redacted]% higher than the indicative prices that RMP was quoting for Wyoming QFs for 20-year contracts during the time RMP was developing the Pryor Mountain project.

Q. IS IT NOT TRUE THAT THE CHARACTERISTICS OF WIND FACILITIES VARY FROM SITE TO SITE? WHY SHOULD THE TYPICAL WYOMING WIND QF AVOIDED COST BE USED TO BENCHMARK THE COST EFFECTIVENESS OF THIS RMP-DEVELOPED PROJECT?

A. While it is true that the characteristics of wind facilities can vary from site to site, the record shows that the avoided costs that RMP provided to QFs for power *at this site* were also considerably less than the revenue requirement that RMP is seeking to recover from customers in this case. Specifically, [redacted]

[50] In response to UAE Data Request 7.3, included in UAE Exhibit RR 1.17, RMP provided pertinent data responses from Wyoming dockets: Wyoming Docket No. 20000-545-ET-18, RMP response to WIEC-VK-TR Data Request 3.13, Attachment WIEC-VK-TR 3.13-1; and Wyoming Docket No. 20000-578-ER-20, RMP response to WIEC Data Request 29.4. The average avoided cost increases from $25.99 to $26.48/MWh if certain transmission investments are assumed to occur. For those QFs that were provided a higher price conditional on new transmission, the avoided cost increased $1.43/MWh.

[redacted][51]

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE PRYOR MOUNTAIN REVENUE REQUIREMENT?

A. I recommend that RMP be paid $26.00/MWh for each MWh that the Pryor Mountain project produces for 20 years, and that the PTC and REC revenues be retained by the Company.[52] The $26.00/MWh would be included in net power costs ("NPC").

Q. WHY IS SUCH A TREATMENT REASONABLE?

A. [redacted]. RMP has represented to this Commission that the Company can develop projects at a lower cost and lower risk to customers than it can provide through QF power purchase agreements ("PPAs").[53] The Commission should hold the Company accountable to this claim and should not authorize a revenue requirement for

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[51] *See* RMP 1st Supplemental Response to UAE Data Request 6.1, Confidential Attachment "Innogy-Bowler Flats Wind – Indicative Pricing Letter 2018_10_05 CONF," included in Confidential UAE Exhibit RR 1.18.
[52] I recommend a 20-year contract consistent with the approved term lengths for QF PPAs at the time Pryor Mountain was being developed. [redacted].
[53] For example, in Docket No. 15-035-53, RMP witness Paul H. Clemens testified: "This robust [RFP] process ensures the Company acquires only what is needed and results in a long-term transaction at the lowest cost possible... PURPA contracts do not go through the same extensive IRP process to determine if they are needed. PURPA contracts do not go through the same competitive bid RFP process including oversight by an independent evaluator to ensure they are lowest cost. PURPA contract executions are not limited to the size of the resource need in the IRP action plan. And, PURPA contracts do not receive the same upper management review and analysis because upper management does not have the discretion to refuse the mandatory purchase obligation and the 20-year contract term established by the Commission." Direct Testimony of Paul H. Clemens, lines 386-399.

the Pryor Mountain project that exceeds the avoided cost the Company was providing to Wyoming QFs. Moreover, my recommendation does not require RMP to recover less revenue from customers than customers would have paid for QF power, but simply the same amount of revenue that would have been paid to QFs. I believe this treatment is eminently reasonable.

Q. HOW HAVE YOU MODELED THIS ADJUSTMENT?

A. For modeling purposes, I have removed the Pryor Mountain project from rate base and its associated expenses from the cost of service. I then substituted into the revenue requirement the equivalent of a PPA at $26.00/MWh. Going forward, I recommend that the cost recovery for this project be treated in this manner, with the $26.00/MWh cost included in NPC and subject to the EBA. To be fair to the Company, the facility would be operated on a "must run" basis, i.e., it would not be placed in the dispatch stack at a marginal cost of $26.00/MWh. At the same time, it could be beneficially curtailed under certain circumstances as I describe below.

Q. ARE YOU PROPOSING THAT THE ALLOWED REVENUE REQUIREMENT FOR ALL RMP-DEVELOPED WIND PROJECTS GOING FORWARD BE DETERMINED BY THE AVOIDED COST RATE THAT RMP OFFERS TO QFS FOR COMPARABLE WIND PROJECTS?

A. No, I am not proposing such a systemic change at this time. For now, I believe it is reasonable that each RMP project should be viewed on its own merit. However, for the Pryor Mountain project, which was fast tracked by the Company and has since turned out to be [redacted]% more expensive than the avoided cost rate calculated for similarly situated QFs, I find the argument for not allowing RMP to recover any more than the avoided cost rate to be compelling.

Q. WHAT SHOULD OCCUR AFTER 20 YEARS?

A. I think several options are possible after 20 years. One option would be for the Company to be free to sell the power into the market starting in 2040 and retain the revenues for shareholders. Alternatively, the Company could propose to include the output in its revenue requirement at that time under terms the Commission determines to be reasonable. Finally, the Commission could provide the Company with the option upfront to continue to be paid $26.00/MWh for the output of the project until it is retired from service.

Q. CAN YOUR RECOMMENDED TREATMENT BE ADAPTED TO HANDLE SITUATIONS IN WHICH RMP WOULD FIND IT BENEFICIAL TO CURTAIL OUTPUT FROM THE PRYOR MOUNTAIN PLANT IN RESPONSE TO SUFFICIENTLY NEGATIVE PRICES IN THE ENERGY IMBALANCE MARKET ("EIM")?

A. Yes. If all of the cost recovery for the project were treated as a fixed cost (as RMP proposes) and the variable cost were treated as zero, then there might be occasions in which RMP would find it advantageous to curtail output from Pryor Mountain in response to sufficiently negative prices in the EIM. Pursuant to the current EBA, 100% of the net benefits from such a curtailment would flow to customers. Under my Pryor Mountain proposal, if such a curtailment opportunity arises, I recommend that RMP continue to be compensated $26.00/MWh for any energy verifiably curtailed, with the net benefits from the negative EIM pricing flowing 100% to customers. This would maintain the same incentive to economically curtail Pryor Mountain's wind generation that would otherwise obtain if RMP's proposed revenue requirement were to be approved. However, given the need to measure the amount of energy actually curtailed from Pryor Mountain, it would be preferable for curtailment of other available Company resources to be implemented prior to exercising a Pryor Mountain curtailment option.

Q. WHAT IS THE IMPACT OF YOUR PRYOR MOUNTAIN ADJUSTMENT ON THE UTAH REVENUE REQUIREMENT?

A. The resulting impact from my Pryor Mountain adjustment is a [redacted] reduction to the Utah revenue requirement deficiency. This adjustment is shown in Confidential UAE Exhibit RR 1.13.

XV. <u>RETURN ON EQUITY</u>

Q. WHAT ROE IS RMP PROPOSING?

A. RMP is proposing a return on equity of 10.20%.[54]

Q. DOES UAE SUPPORT RMP'S REQUEST?

A. No. Although UAE is not presenting testimony on RMP's cost of capital, UAE recognizes that the Division of Public Utilities ("Division") and Office of Consumer Services ("OCS") are challenging the Company's proposal and are recommending ROEs of 9.25%[55] and 9.00%,[56] respectively. UAE defers to the Division and the OCS on this subject.

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[54] *See* Direct Testimony of Ann E. Bulkley, lines 1617-1618.
[55] Direct Testimony of Casey J. Coleman, lines 64-66.
[56] Direct Testimony of J. Randall Woolridge, lines 2064-2066.

Q. DO YOU INCLUDE AN ROE ADJUSTMENT IN YOUR REVENUE REQUIREMENT CALCULATION?

A. Yes. In order to present a more realistic revenue requirement than would occur by leaving the Company's 10.20% ROE unchanged, I have used an ROE of 9.50% as a placeholder in presenting UAE's recommended revenue requirement. The Company recently stipulated to an ROE of 9.50% in its general rate case in Washington.[57]

Q. IN USING THIS PLACEHOLDER ROE, ARE YOU INTENDING TO SUPPLANT THE COMMISSION'S CONSIDERATION OF TRADITIONAL COST-OF-CAPITAL ANALYSIS OFFERED BY OTHER PARTIES?

A. No. The inclusion of the 9.50% ROE in UAE's revenue requirement is simply illustrative and is intended to provide a more realistic depiction of UAE's proposed revenue requirement that would occur absent any adjustment at all.

Q. WHAT WOULD BE THE REVENUE REQUIREMENT IMPACT IF RMP'S ROE WERE SET AT 9.50%?

A. The revenue requirement impact of setting RMP's allowed ROE equal to 9.50% is presented in UAE Exhibit RR 1.14. It reduces the Utah revenue requirement by approximately $**37,260,685** relative to RMP's filed case.

Note that in Table KCH-1, I show the impact of this ROE adjustment prior to my Return on Retired Wind Plant and Craig SCR adjustments. This means the revenue requirement impact of the ROE adjustment is calculated prior to considering the reduced returns for these two specific items that I present in my testimony below. I point this out

[57] WA Docket No. UE 191024 et al., Settlement Stipulation (July 17, 2020), ¶ 13, Footnote 8.

because the impact of each individual adjustment in Table KCH-1 is sensitive to where it appears in the sequence of adjustments. Consistent with this principle, the rate impacts for the Return on Retired Wind Plant and Craig SCR adjustments are calculated relative to the WACC associated with an ROE of 9.50%, not RMP's recommended WACC, as they are presented after the 9.50% ROE is taken into account.

XVI. ALLOWED RETURN ON RETIRED WIND PLANT

Q. PLEASE DESCRIBE YOUR ADJUSTMENT FOR THE ALLOWED RETURN ON RETIRED WIND PLANT.

A. As I discussed previously in my testimony, each of the 12 Repowered Wind Projects had a substantial portion of original equipment retired when the wind plants were repowered. RMP proposes to recover the cost of the original investment that it retired, plus a return on that investment, for each of the Repowered Wind Projects. Whereas earlier in my testimony I addressed the appropriate measurement of the retired asset value in the test period, in this section I address the appropriate return on the retired wind assets.

In Docket No. 17-035-39, I noted the significant disparity between the benefits to RMP from its expected earnings on its investment in the Repowered Wind Projects compared to the projected benefits to customers.[58] To mitigate this disparity, I recommended a reduction of 200 basis points to the authorized rate of return on common equity applied to the undepreciated balance of the plant that RMP would retire to install the repowering investment. Although the Commission granted preapproval to 11 of the 12

[58] *See, for example*, Docket No. 17-035-39, Response Testimony of Kevin C. Higgins, lines 72-80 and 778-797.

repowering projects proposed by RMP, the Commission reserved the question of the appropriate return on the retired assets for this general rate case.[59]

To ensure that the Company and customers are reasonably sharing the risks and benefits of the repowered projects, I continue to recommend that a reduction of 200 basis points be applied to the authorized rate of return on common equity applied to the undepreciated balance of the plant, which I note is no longer used and useful. The adjustment I recommend is intended to better balance, upfront, the potential benefits from these projects for both customers and the Company.

Q. HAVE YOU PREPARED A COMPARISON OF THE BENEFITS TO CUSTOMERS AND SHAREHOLDERS FROM THE REPOWERED WIND PROJECTS?

A. Yes. The relative benefits to customers and shareholders from the Repowered Wind Projects as proposed by RMP for the period 2021-2050 are shown in Table KCH-4, below. The lower end of the customer benefits range is for RMP's LN scenario and the upper end is for the MM scenario. Note that starting the analysis in 2021 (rather than 2018 as RMP does) and discounting costs and benefits to 2021 (rather than 2018) increases the RMP net benefit calculation.

The benefit to RMP shown in Table KCH-4 is equal to the present value of the after-tax return on the equity component of the capital structure assumed by Mr. Link in his analysis.

[59] *See* Docket No. 17-035-39, Report and Order issued May 25, 2018 at 26. "…[W]e reserve for consideration in an appropriate future ratemaking proceeding the degree, if any, to which the rate of return on those [retired] assets should be adjusted."

Table KCH-4
Comparison of Repowered Wind Project Benefits to Customers and RMP
Using RMP's Measurement of Customer Benefits

Net Benefits to Customers and RMP Based on RMP's Proposal (Total Company)		
Timeframe	**Customer Benefit Range (Millions)**	**RMP Benefit (Millions)**
2021 - 2050	$214 $396	$285

Net Benefits to Customers and RMP Based on RMP's Proposal (Utah Share)		
Timeframe	**Customer Benefit Range (Millions)**	**RMP Benefit (Millions)**
2021 - 2050	$94 $173	$125

Note: Projected customer benefits are shown as positive entries, even though customer benefits have a negative sign in Mr. Link's tables. RMP benefits are also shown as positive entries.

As shown in Table KCH-4, the projected benefits from the Repowered Wind Projects are materially weighted in favor of the Company as compared to customers in the LN scenario. For the purpose of comparing the relative benefits to customers and RMP, I believe the LN scenario should be given more weight than the MM scenario because it better reflects our current relatively low-gas-cost environment and the absence of carbon taxes. With the risks of plant underperformance generally falling on customers, I do not think a proposition in which the expected (low-risk) benefit to the Company is greater than the (higher-risk) benefit to customers in the LN scenario is balanced or reasonable.

A further consideration is that the Repowered Wind Projects are not a typical utility investment proposition. Utility generation projects are typically driven by the need to meet reliability requirements, load growth, and/or to replace retired plant that has come to the end of its useful life. That is not the case here. Rather, the Repowered Wind Projects are best characterized as "opportunity" investments that seek to take advantage of the availability of PTCs before federal tax credits begin to phase out. The relative benefits to customers, taking account of the range of risks to customers, in relation to the benefits to RMP, should be considered as part of the Commission's revenue requirement review in this case. In my opinion, the overall equities are not sufficiently balanced or reasonable to support approval of the Company's revenue requirement request for these projects without an adjustment to the allowed return on the retired wind assets.

Q. HOW DOES YOUR RECOMMENDATION FOR A 200 BASIS POINT ADJUSTMENT APPLIED TO THE EQUITY RETURN ON THE RETIRED ASSETS BETTER BALANCE THE EQUITIES BETWEEN CUSTOMERS AND SHAREHOLDERS?

A. My recommended adjustment would increase the benefits to customers over the period, 2021-2050, by $50 million, while reducing the projected benefits to the Company by $37 million.[60] The reason for the difference between these two values is that customer benefits are measured on a pre-tax basis (*i.e.,* the measurement takes into account income tax expense paid by customers) whereas Company benefits are measured on an after-tax basis. If this adjustment to the return on common equity is made, the resulting benefit for the Company would be reduced to $248 million, while the projected benefits to customers under the LN scenario would be increased to $264 million. These results are summarized in Table KCH-5, below. For ease of comparison, I have also replicated Table KCH-4, and renumbered it as Table KCH-5a, and placed it immediately below Table KCH-5.

[61] The calculations supporting these figures are contained in a Confidential UAE workpaper.

Table KCH-5 (UAE's Proposal)
Comparison of Repowered Wind Project Benefits to Customers and RMP
After Adjusting Allowed Return on Retired Assets

Net Benefits to Customers and RMP Based on 200 B.P. Adjustment to ROE on Retired Plant (Total Company)			
Timeframe	Customer Benefit Range (Millions)		RMP Benefit (Millions)
2021 - 2050	$264	$446	$248

Net Benefits to Customers and RMP Based on 200 B.P. Adjustment to ROE on Retired Plant (Utah Share)			
Timeframe	Customer Benefit Range (Millions)		RMP Benefit (Millions)
2021 - 2050	$115	$195	$108

Note: Projected customer benefits are shown as positive entries, even though customer benefits have a negative sign in Mr. Link's tables. RMP benefits are also shown as positive entries.

Table KCH-5a (PacifiCorp's Proposal)
Comparison of Repowered Wind Project Benefits to Customers and RMP
Using RMP's Measurement of Customer Benefits

Net Benefits to Customers and RMP Based on RMP's Proposal (Total Company)			
Timeframe	Customer Benefit Range (Millions)		RMP Benefit (Millions)
2021 - 2050	$214	$396	$285

Net Benefits to Customers and RMP Based on RMP's Proposal (Utah Share)			
Timeframe	Customer Benefit Range (Millions)		RMP Benefit (Millions)
2021 - 2050	$94	$173	$125

Note: Projected customer benefits are shown as positive entries, even though customer benefits have a negative sign in Mr. Link's tables. RMP benefits are also shown as positive entries.

I believe that my proposed adjustment to the allowed return on retired plant produces a more reasonable balancing of the benefits between customers and the Company.

Q. WHAT IS THE IMPACT OF YOUR ADJUSTMENT ON THE UTAH REVENUE REQUIREMENT?

A. The resulting impact from my adjustment is a **$3,145,085** reduction to the Utah revenue requirement deficiency measured against the placeholder 9.50% ROE discussed previously in my testimony. This adjustment is shown in UAE Exhibit RR 1.15.

XVII. CRAIG 2 SCR

Q. BRIEFLY DESCRIBE THE CRAIG 2 SCR PROJECT.

A. The Craig 2 SCR project consists of a $37.8 million investment in pollution control equipment at the Craig 2 power plant that went into service December 2017.[61] According to RMP witness James C. Owen, the Craig 2 SCR was required by the Clean Air Act Regional Haze Rules and the associated state of Colorado Regional Haze State Implementation Plan ("SIP") to be installed by January 30, 2018.[62]

The Craig 2 power plant is jointly owned by Tri-State Generation and Transmission Association, Inc., Salt River Project, Platte River Power Authority, Public Service Company of Colorado, and PacifiCorp, with PacifiCorp owning 19.28% of the unit (as well as Craig 1). The terms and conditions of joint ownership in Craig 2 are governed by a Participation Agreement. The owners of Craig 2 recently announced that it would be shut down by September 30, 2028.

As explained by Mr. Owen, PacifiCorp independently assessed the benefits from the Craig 2 SCR project against a hypothetical scenario in which the unit was shut down early.[63] PacifiCorp's analysis, conducted in 2013, concluded that shutting down the plant before the end of 2017 would be more cost effective than installing the SCR equipment. [redacted][64]

[61] Direct Testimony of James C. Owen, lines 125-126.
[62] *Id.* at lines 58-62.
[63] *Id.* at lines 91-93.
[64] PacifiCorp Memorandum, "Economic Analysis of Craig Environmental Investments," pp. 1-2 (July 11, 2013).

Q, DID THE COMPANY RECOMMEND AGAINST MAKING THE SCR INVESTMENT?

A. Yes. As explained by Mr. Owen, the Company voted no with respect to the Craig 2 SCR project. Mr. Owen states that "As a minority owner, the Company recognized that under the terms of the Craig Participation Agreement, its vote alone would not change the outcome with the other joint-owners voting 'yes', and the Company remained obligated to pay its share of the Craig Unit 2 SCR."[65] Mr. Owen further explains that:

> The ultimate determination of the legal review of the Craig Participation Agreement was that the Company had the right to challenge the majority's decision, but there was little to no opportunity to successfully challenge the project through arbitration or litigation. This was primarily because the project met the requirements under the Craig Participation Agreement...[66]

Consequently, the Company did not pursue arbitration or litigation. RMP is seeking recovery of the Craig 2 SCR costs through inclusion in rate base in this case.

Q. IS FULL RECOVERY OF THE CRAIG 2 SCR COSTS REASONABLE?

A. This is a difficult question. In my opinion, the Company acted in customers' best interests by independently evaluating the economics of the SCR investment and voting no on the decision to move forward with the investment. I believe the stand that the Company took on this matter is commendable. On the other hand, the fact remains that Utah customers are being asked to pay for an investment that was not cost effective, indeed not prudent, at the time it was made. Further, the Participation Agreement that the Company entered into in 1992, which apparently impeded the Company's ability to challenge the investment decision, was negotiated by Company management, not by customers. As a case in point,

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[65] Direct Testimony of James C. Owen, lines 100-104.
[66] *Id.* at lines 111-115.

Section 37 of the Participation Agreement provides joint owners the option to withdraw their Craig facilities ownership for compensation at fair market value, but the agreement specifies that such notice would be required by June 1, 2011, an unfortunate piece of timing given that the SCR project was proposed for inclusion in the 2013 capital expenditures budget. Such a withdrawal might have been a potential remedy for PacifiCorp had the opportunity for withdrawal been negotiated differently.

In light of these competing equities, I recommend that RMP be allowed to recover the cost of the Craig 2 SCR investment in rates but should earn less than a full return on rate base for this project. Specifically, I recommend that the return on equity for this project be set equal to the cost of long-term debt, plus a tax gross up. I believe this approach strikes a reasonable balance between the interests of customers and shareholders.

Q. WHAT IS THE IMPACT OF YOUR CRAIG 2 ADJUSTMENT ON THE UTAH REVENUE REQUIREMENT?

A. The resulting impact from my Craig 2 adjustment is a **$420,498** reduction to the Utah revenue requirement deficiency measured against the placeholder 9.50% ROE discussed previously in my testimony. This adjustment is shown in UAE Exhibit RR 1.16.

XVIII. DEER CREEK MINE RECOVERY ROYALTIES

Q. WHAT ARE THE DEER CREEK MINE RECOVERY ROYALTIES?

A. My understanding is that the Company anticipates that the Department of the Interior's Office of Natural Resources Revenue ("ONRR") will assess royalties based on recoverable costs for Deer Creek coal production, mine closure, and final reclamation activities. It is also my understanding that the Company does not have a specific timeline of when actual royalty obligations will be settled with the ONRR, nor has a final royalty payment been negotiated with the ONRR.[67]

Q. WHAT AMOUNT OF RECOVERY ROYALTIES DOES RMP FORECAST?

A. In its direct filing, the Company estimated Utah-allocated recovery royalties of $5.2 million[68] which was based on Total Company royalties of $12.1 million. In discovery, RMP revised its Utah-allocated estimate to $7.6 million, based on Total Company royalties of $17.7 million forecast to accrue by the end of 2024.[69]

Q. HOW DOES RMP PROPOSE TO ADDRESS RECOVERY ROYALTIES IN THIS CASE?

A. RMP proposes to use Excess Deferred Income Taxes ("EDIT") resulting from the TCJA to offset the Utah share of projected recovery royalties, along with other Deer Creek Mine closure costs.[70]

Q. DO YOU AGREE WITH RMP'S PROPOSAL TO USE EDIT TO OFFSET RECOVERY ROYALTIES?

A. No. As RMP acknowledges, RMP has not paid these recovery royalties and the final amount will not be known until negotiations are underway and settled with the ONRR.[71] Therefore I do not believe it is appropriate to utilize EDIT funds – or any customer funds – to pay for projected royalties at this time. Instead, I recommend that the EDIT that

[67] My understanding is based on the Reply Testimony of Shelley E. McCoy (Exhibit PAC/3100), p. 45, filed in Oregon Docket No. UE 374.
[68] Exhibit RMP__(SRM-3), p. 8.14.3, p. 8.14.6.
[69] *See* RMP response to UAE Data Request 4.10, included in UAE Exhibit RR 1.17.
[70] Direct Testimony of Steven R. McDougal, lines 924-927; Exhibit RMP__(SRM-6).
[71] *See* RMP response to UAE Data Request 4.10, included in UAE Exhibit RR 1.17.

RMP proposes to apply to the recovery royalties be returned to customers through Schedule 197.

As part of its rate mitigation proposal, RMP proposes to credit customers with two-thirds of the remaining TCJA regulatory liability in 2021 and one-third in 2022 through Schedule 197.[72] Using this approach, I recommend that an additional $3,499,460 in deferred tax benefits be returned to customers through Schedule 197 in 2021, phasing down to $1,749,730 in 2022, to account for the amounts that RMP applied to recovery royalties in its direct filing.

Since I recommend that this credit be effectuated through Schedule 197, it does not impact the base revenue requirement.

XIX. PROPOSED INCLUSION OF PTCS IN THE EBA

Q. PLEASE DESCRIBE RMP'S PROPOSAL TO INCLUDE PTCS IN THE EBA.

A. As discussed in Direct Testimony of David G. Webb, RMP proposes include PTCs in the EBA, where they would be tracked and trued-up along with net power cost.[73]

Q. WHAT IS YOUR RESPONSE TO THIS PROPOSAL?

A. I recommend that RMP's proposal be rejected. PTCs are currently recovered in base rates at pro forma levels and are excluded from the EBA. I do not see a good reason to change this ratemaking treatment.

[72] Direct Testimony of Joelle R. Steward, lines 361-366.
[73] Direct Testimony of David G. Webb, lines 729-736.

Q. PLEASE EXPLAIN YOUR REASONING.

A. As an initial matter, the Commission should be wary of attempts by RMP to expand the EBA beyond its initial scope in order to shift even greater risks from the Company to customers. In the Commission's comprehensive Phase II order implementing the EBA in 2011,[74] PTCs are not even mentioned, even though the PTC was enacted in 1992 and had been subject to several extensions by the time of the Commission's order. PTCs were clearly not part of the original justifications for the EBA.

One of the major justifications for adopting the EBA in the first instance was concerns about volatility in wholesale power prices and fuel prices. Yet unlike market prices for power or fuel, PTC *values* do not change from year to year, except in a reasonably predictable manner through an inflation adjustment. Thus, there is no PTC price volatility to justify recovery through an adjustor mechanism. And although wind power output is variable, customers are already exposed to the full risk of acquiring replacement power when wind production is below expectations. Including PTCs in the EBA would only add to that customer risk exposure.

Moreover, I believe that including PTCs in the EBA is particularly inapt in this general rate case – a proceeding in which RMP proposes to add some [redacted] billion in wind and associated transmission investment into rate base. Much of this investment has been justified by the Company based on the projected benefits from PTCs. As I discussed above, the investment benefits to RMP from pursuing these opportunity investments are significant and relatively low risk to the Company, whereas the benefits to customers

[74] Docket No. 09-035-15, Corrected Report and Order issued March 3, 2011.

from these investments will vary depending on future power prices and CO_2 regulations. RMP's proposal to include PTCs in the EBA would make the potential benefits to customers from the Company's large investments in wind and wind-supporting transmission even more variable than they already are. RMP's proposal should be rejected.

XX. <u>DOCUMENTATION OF DATA RESPONSES RELIED ON</u>

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 1.17. Confidential data responses that I relied on are provided in Confidential UAE Exhibit RR 1.18.

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

A. Yes, it does.