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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. 13-035-184**

PREFILED DIRECT TESTIMONY OF KEVIN C. HIGGINS

[REVENUE REQUIREMENT]

PUBLIC VERSION

The UAE Intervention Group (UAE) hereby submits the Prefiled Direct Testimony of Kevin C. Higgins on revenue requirement issues.

DATED this 1st day of May, 2014.

/s/*Gary A. Dodge*________________
Gary A. Dodge,
Attorney for UAE

BEFORE

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Direct Testimony of Kevin C. Higgins

on behalf of

UAE

Docket No. 13-035-184

[Revenue Requirement]

PUBLIC VERSION

May 1, 2014

DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 215 South State Street, Suite 200, 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. Energy Strategies is a private consulting firm specializing 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 Intervention Group ("UAE").

Q. Please describe your professional experience and 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 this Commission?

A. Yes. Since 1984, I have testified in thirty-one dockets before the Utah Public Service Commission on electricity and natural gas matters.

Q. Have you testified previously before any other state utility regulatory commissions?

A. Yes. I have testified in approximately 150 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, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings at the Federal Energy Regulatory Commission.

OVERVIEW AND CONCLUSIONS

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses certain revenue requirement issues in this general rate case. As part of my testimony, I make recommendations to adjust the revenue requirement proposed by Rocky Mountain Power ("RMP," "Company," or, as applicable, "PacifiCorp"). As I have not undertaken an exhaustive audit of all test period revenue, expenses, and other projections of RMP, absence of comment on my part regarding a particular issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue.

Q. What revenue increase is RMP recommending for the Utah jurisdiction?

A. In its direct filing, RMP proposed a revenue increase of $76,252,101, or 4.1% percent on an annual basis. On April 10, 2014, RMP updated its net power costs, which had the effect of reducing net power costs allocated to Utah by approximately $5.0 million.

Q. Please summarize the revenue requirement adjustments you are recommending.

A. In total, my recommended revenue requirement adjustments reduce Utah base revenue requirement deficiency by **$27,302,497**, after taking account of certain expenses that I am recommending be recovered outside of base rates. These adjustments are presented in Table KCH-1 below. My recommended adjustments are as follows:

- Revenues from Renewable Energy Credit sales should be increased to reflect new sales agreements that have been consummated since the date of the Company's filing. This adjustment results in a reduction to the Utah revenue requirement deficiency of **$427,153**.
- RMP has not fully accounted for increased special contract revenues that are scheduled to be recovered during the test period. Correcting for this omission results in a **$269,085** reduction to the Utah revenue requirement deficiency.
- The inflation escalator applied by RMP to its test period non-labor O&M expense is unwarranted and should be removed. This adjustment reduces the Utah revenue requirement deficiency by **$2,444,855**.
- I have revised downward RMP's projected Lakeside Unit 2 overhaul expenses for the July 2014 to June 2018 period to adjust for the Company's tendency to overestimate projected generation overhaul costs for ratemaking purposes. This adjustment reduces the Utah revenue requirement deficiency by **$161,535**.
- RMP's generation overhaul costs should also be adjusted by removing the historical expenses associated with the Carbon Plant, which will be retired before the end of the test period. This adjustment reduces the Utah revenue requirement deficiency by **$274,160**.
- The test year level of FAS 87 pension expense should be adjusted to reflect the impact of RMP's revised 2014 plan expense. This adjustment reduces RMP's Utah revenue requirement deficiency by **$214,350**.

- The test year level of other post retirement benefits – FAS 106 ("PBOP") expense should be adjusted to reflect the impact of RMP's revised 2014 plan expense. This adjustment reduces RMP's Utah revenue requirement deficiency by **$123,236**.
- Certain legal expenses incurred by the Company that pertain exclusively to shareholder interests should not be recovered from customers in rates. Removal of these expenses reduces RMP's Utah revenue requirement deficiency by **$1,455,098**.
- RMP inadvertently included in its revenue requirement costs associated with recovery of unpaid accounts that is now handled by collection agencies. Correcting this error reduces Utah revenue requirement deficiency by **$451,308**.
- RMP's employee count has declined relative to the June 2013 date the Company used for establishing the baseline for its test period wage and benefits expense. I recommend basing wage and benefit expense for the test period on more recent January 2014 employment levels. Accordingly, I have reduced test period wage and benefits expense to account for a reduction of 9 full-time equivalent employees ("FTEs") at the Carbon Plant and 17 FTEs elsewhere in the Company. This adjustment reduces Utah revenue requirement deficiency by **$1,155,605**.
- Because the Carbon Plant will be retired before the end of the test period, O&M expenditures and wage and benefits expenses incurred at that facility should be viewed as non-recurring in nature and should be removed from base rates, although the Company should still be permitted to recover these costs, to the

extent they are prudently incurred, either through a rider that expires in twelve months or amortized as part of a regulatory asset. These adjustments would reduce the Utah revenue requirement reflected in base rates by **$1,912,027** for non-labor O&M expenditures and **$2,489,639** for Carbon-related wage and benefits expense that is incremental to the wage and benefits adjustment discussed above.

- The opportunity cost of holding incremental reserves to provide wind integration is recovered from retail customers as part of net power cost. However, these opportunity costs are not recovered from third-party wind facilities on the Company's system through PacifiCorp's Open Access Transmission Tariff ("OATT"), resulting in a cross subsidy from retail customers. I recommend adjusting net power costs to assign a pro rata share of wind integration costs to third-party wind facilities. This adjustment reduces Utah revenue requirement deficiency by **$1,034,310**.
- I recommend that the Commission disallow recovery of the costs attributable to the DC Intertie Agreement because the cost is unreasonable in relation to the benefit. This adjustment reduces Utah revenue requirement deficiency by **$2,002,665**.
- I recommend setting base net power costs in this case based on the Company's planned extension of the Naughton Unit 3 coal operations. This adjustment reduces the Utah revenue requirement deficiency by **$5,206,700**. If, for some reason, the Company's proposed extension is rejected by regulatory authorities,

the incremental costs attributed to that rejection can be deferred for future ratemaking treatment.

- RMP is proposing to change the way prepaid pension assets are treated for ratemaking purposes in Utah by including its prepaid pension asset and accrued other post-retirement liability in rate base, net of accumulated deferred income taxes ("ADIT"). The Commission should reject this change. From a process standpoint, the Company's proposal suffers from being a prime example of adverse selection, in which the Company's specialized knowledge of its circumstances makes it far more likely to suggest a change in regulatory treatment under conditions in which the change inures to its benefit than when such a change inures to its disadvantage. The Company's proposal also raises serious concerns with respect to notice and retroactivity and its adoption would result in an unreasonable transfer of risk to customers. This adjustment reduces Utah revenue requirement deficiency by **$7,493,354**.
- I recommend an adjustment to remove contingency costs for new investments that had been included in the Company's filing, but which since have been revised downward based on the Company's actual experience since the filing date. This adjustment reduces Utah revenue requirement deficiency by **$187,417.**

I will explain the basis for each of these adjustments in the following sections.

Table KCH-1

Summary of Revenue Requirement Impact of UAE Adjustments

	Adjustment
REC Revenue Adjustment	(427,153)
Special Contract Revenue Adjustment	(269,085)
O&M Expense Escalation Adjustment	(2,444,855)
Generation Overhaul Expense Adjustment - Lake Side 2	(161,535)
Generation Overhaul Expense Adjustment - Carbon	(274,160)
Pension Expense Adjustment	(214,350)
Post-Retirement Benefits Other than Pensions (PBOP) Exp. Adjustment	(123,236)
Legal Expense Disallowance Adjustment	(1,455,098)
Collection Expense Adjustment	(451,308)
Wage & Benefit Expense Adjustment	(1,155,605)
Carbon O&M Expense Adjustment - Non-Labor*	(1,912,027)
Carbon Labor Expense Adjustment*	(2,489,639)
Third Party Wind Integration Adjustment	(1,034,310)
DC Intertie Expense Adjustment	(2,002,665)
Naughton Unit 3 Extended Coal Operation Adjustment	(5,206,700)
Prepaid Pension Asset Adjustment	(7,493,354)
Contingency Reserve Adjustment	(187,417)
Total UAE Test Period Adjustments	(27,302,497)

*** Removed from base rates; proposed recovery through an alternative ratemaking mechanism.**

Q. Have you calculated the net change in Utah revenue requirements associated with your recommended adjustments in combination with the cost of capital recommendations in this case?

A. Yes. I have calculated the net change in Utah revenue requirements using the cost of capital proposed by RMP, the Division of Public Utilities (”DPU”), the Office of Consumer Services (“OCS”). This information is summarized in Table KCH-2, below.

Table KCH-2

Required Base Rate Increase to Achieve Recommended Rate of Return on Rate Base

RMP As-Filed	RMP With NPC Update	UAE Adjustments With RMP ROR	UAE Adjustments With DPU ROR	UAE Adjustments With OCS ROR
$76,252,101	$71,252,101	$43,950,178	$ 4,663,317	$ 4,230,345

In addition to the base rate increases shown in Table KCH-2, my recommendations provide for an additional $4,401,666 of Utah revenue requirement related to the operations of the Carbon plant to be recovered through an alternative ratemaking mechanism.

RENEWABLE ENERGY CREDIT REVENUES

Q. Generally, what role do renewable energy credits play in setting rates for RMP?

A. RMP is able to sell certain renewable energy attributes associated with the generation output of renewable generation facilities such as wind, geothermal, and small hydro plants. These attributes have value to certain other utilities and parties that are required to procure specified amounts of renewable energy pursuant to state statutes and regulations. When these attributes are sold in the marketplace, the exchanged product has come to be known as Renewable Energy Credits ("RECs"). Because REC sales are made using assets that are paid for by customers, the revenues from REC sales are appropriately treated as a revenue credit against the revenue requirement recovered from customers.

One hundred percent of projected REC sales in the test period have been credited to customers. The projected REC sales will eventually be trued up to actual through the REC Balancing Account ("RBA") for later refund or credit, with the balance earning a carrying charge equal to the Company's approved long-term cost of debt. In order to provide RMP an incentive to make REC sales, the stipulation approved in the last general rate case, Docket No. 11-035-200, allows RMP to retain 10 percent of incremental REC revenues received under contracts entered after July 1, 2012, starting June 1, 2013.[1] RMP indicates that the Company will account for the 10 percent retention through the RBA.[2]

Q. What level of REC sales has RMP projected in the test period in this case?

A. In its filing, RMP has projected test period REC revenues of $3,679,955 on a total Company basis. This is a substantial reduction relative to past years. For example, REC revenues were $50.8 million in 2009, $101.1 million in 2010, $72.8 million in 2011, and $81.3 million in 2012, before declining to just $7.6 million in 2013.[3]

Q. What adjustment are you recommending for REC revenues?

[1] See paragraph 39 in Stipulation approved in Docket No. 11-035-200. For the period between October 12, 2012 and May 31, 2013, RMP was permitted to keep 10 percent of the REC revenues that were incremental to the $25 million, Utah-allocated, test period REC revenue projected in the 11-035-200 rate case.
[2] RMP Exhibit (SRM-3), page 3.4, Description of Adjustment.
[3] Sources: May 24, 2011 RMP Compliance Filing in WA Docket UE-100749, Redacted Attachments 1 & 2; Exhibit RMP_(SRM-1 through 3), page 3.2, WY Docket 20000-411-EA-12 and RMP response to UAE Data Request 2.4, Attachment UAE 2.4 in Docket 13-035-184.

A. According to RMP's Supplemental Response to UAE 2.2, there has been a small increase in REC sales projected for the test period since the date of the Company's filing. This increase should be recognized in the Utah revenue requirement. This adjustment is presented in UAE Exhibit RR 1.1 and results in a reduction to Utah revenue requirement deficiency of **$427,153**.

SPECIAL CONTRACT REVENUES

Q. Please explain the basis for your adjustment for special contract revenues.

A. RMP has not fully accounted for increased special contract revenues that are scheduled to be recovered during the test period. Specifically, [redacted] is subject to a [redacted] percent base rate increase on January 1, 2015, per the terms of its contract. In addition to this [redacted] percent increase, [redacted].[4]

While RMP has appropriately incorporated [redacted]

Q. Has the Company provided an explanation for why [redacted] was not included in its filing?

[4] Confidential: See Electric Service Agreement between PacifiCorp [redacted]

A. RMP indicated in discovery that the [redacted] was not reflected in its filing because the Company is proposing a rate effective date of September 1, 2014 in this case, while the [redacted] will not be effective until January 1, 2015.[5]

Q. Do you agree with the Company's rationale for not including this revenue in its filing?

A. No, I do not. The [redacted] is a known and measurable change that will occur during the test period ending June 2015. Therefore, it properly should be recognized as revenue in the determination of the test period revenue deficiency in this case.

Q. What is your proposed ratemaking treatment for the revenues resulting from this [redacted]?

A. I have estimated the revenue impact of this change by applying this [redacted] estimated by RMP. Since the [redacted] will occur January 1, 2015, which is mid-test period, I have reflected approximately one-half of the annualized increase, based on the proportion of kilowatt-hours projected for [redacted] relative to total test year kilowatt-hours for [redacted] as forecast by RMP.

I note that since the [redacted] will occur January 1, 2015, which is after the proposed rate effective date in this case, it is likely that this

[5] See RMP's response to UAE Data Request 9.1 (Confidential).

increase will be applied [redacted] My revenue adjustment excludes these potential incremental revenues, and thus is conservative. I recommend that any incremental revenue increase, [redacted] be addressed as part of the rate spread considerations in this case.

Q. What is the revenue requirement impact of your adjustment to special contract revenues?

A. The resulting impact from my special contract revenue adjustment is a **$269,085** reduction to the Utah revenue requirement deficiency. This adjustment is presented in UAE Exhibit RR 1.2.

O&M EXPENSE ESCALATION

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 test period 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 June 2013 to June 2015. To apply this cost escalator, RMP starts with its actual non-labor O&M expense for the base period, July 2012 to June 2013. RMP then applies a series of escalation factors to the base-period cost of its materials and services, typically using indices for electric utility costs produced by Global Insight.

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

First, at a broad policy level, I have concerns as an economist about regulatory pricing formulations that 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.

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. This Commission had a long practice of requiring utilities to use <u>historic</u> 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. The Commission has only relatively recently begun 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 <u>investment</u> cost than might occur with an historic test period. Since first allowing projected test periods in 2008,[6] utility test periods in Utah have reached increasingly further into the future; in the instant case, RMP's projected test period extends 18 months beyond the Company's filing date.

With its inflation adjustment, RMP is attempting to go well beyond simply aligning the test period with its projected 2014-15 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 middle of 2015. RMP should not be rewarded for the use of an aggressively-forward test period with a windfall mark-up of its baseline costs under the guise of an inflation adjustment. The Commission should not allow the setting of a future test period to also become a vehicle for utility recovery of such "pseudo costs."

The best evidence of what it costs RMP for non-labor O&M is the Company's actual costs recorded in the base period, adjusted for certain known

[6] The Commission departed from its previous practice of requiring historic 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.

and measurable changes. The cost increases represented by the escalation factors may or may not come to fruition. In any case, 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 costs on to customers.

Q. Have you prepared an analysis that demonstrates how RMP's approach creates an unreasonable cost cushion for the Company?

A. Yes, I have. The results of this analysis are presented in Exhibit UAE RR 1.3. The analysis focuses solely on RMP's non-labor costs, excluding net power cost, as the latter and labor expense are not covered by RMP's inflation adjustment. In preparing the analysis, I examined each of the categories of expense allocated to Utah that were subject to an inflation adjustment by RMP in the last general rate case, Docket No. 11-035-200. These categories of expense are presented in Column (a) of page 1 of the exhibit. Column (b) shows the escalation percentages used by RMP to derive its proposed revenue requirement in that case for the test period, which was June 2012 to May 2013. Column (c) shows RMP's *effective* inflation adjustment for each expense category, after taking account of the fact that certain subsets of expenses were subject to standalone adjustments by RMP outside the generic inflation adjustment. Column (d) shows RMP's proposed revenue requirement for each category of expense as presented in the Company's direct filing in that case, which includes the

Company's inflation adjustment. Column (e) shows RMP's proposed revenue requirement in that case for each category of expense *with the Company's inflation adjustment removed*. Column (f) shows RMP's adjusted *actual* expense for each category as filed in this case for the base period July 2012 through June 2013, which is congruent with the projected test period used in the last rate case for eleven months. This congruence means that the timing of the projected test period in the last rate case and the timing of the base period in this case provide a reasonable basis for comparing RMP's projected costs from the last rate case, with and without projected inflation, to the actual adjusted costs incurred by the Company for substantially the same time period. My analysis shows that RMP's inflation adjustment provides the Company an unnecessary cost cushion in rates that unduly increases electricity prices to customers.

Q. Please explain.

A. Column (g) on page 1 of UAE Exhibit RR 1.3 shows the difference between actual adjusted expenses for the year ending June 2013 and the escalated cost projection that RMP provided in the last rate case for the year ending May 2013. This column shows that actual adjusted expenses were lower than the escalated projected expenses for the majority of expense categories and that, overall, actual adjusted expenses were $46.9 million lower (total Company) than the escalated projected expenses.

Q. Did you examine how actual adjusted expenses compared to RMP's test period projections with the Company's inflation adjustment removed?

A. Yes. Column (h) on page 1 of the exhibit shows the difference between actual adjusted expenses for the year ending June 2013 and the cost projection that RMP provided in the last rate case for the year ending May 2013 *with the Company's inflation assumptions from that case removed*. This column shows that actual adjusted expenses were lower than the un-escalated projected expenses for the majority of the major expense categories and that, overall, actual expenses were $39.4 million lower (total Company) than RMP's projected costs from that case *with projected inflation removed*.

Q. What is your conclusion from this analysis?

A. The analysis shows that RMP's projected non-labor expenses in the last rate case were more than sufficient to recover the Company's actual test period costs without the inflation adder proposed by the Company. RMP's adjustment for projected inflation in the last rate case would have added over $4 million to Utah rates that was completely unnecessary.[7] This result supports my contention that inflation adjustments should not be incorporated into future test periods for ratemaking except under certain extraordinary conditions in which inflation itself is a major problem in the economy.

Q. What are the limited situations in which projected inflation should be considered in ratemaking?

[7] The Utah revenue requirement in the last general rate case was resolved through a stipulation approved by the Commission which did not specifically address the inflation adjustment. Therefore, I do not contend that RMP's proposed inflation adjustment was actually included in Utah rates.

A. The United States experienced major inflation during the late 1970s. In that type of severe increasing-cost environment, some consideration for O&M inflation in a projected test period would probably be necessary. However, we are very far from such a cost environment. Inflation in the United States has been at very low levels for several years. The prospects for core inflation, which excludes the relatively volatile pricing components of energy and food, remain subdued.

Q. Can you cite to any independent sources to support your contention that the prospects for core inflation remain subdued?

A. Yes. I have reviewed the Minutes of the Federal Reserve Open Market Committee for March 18-19, 2014. The published Minutes of that meeting indicate that the Fed's central tendency forecast for core personal consumption expenditures (PCE) inflation is in the range of 1.4% to 1.6% for 2014 and 1.7% to 2.0% for 2015.[8] The Congressional Budget Office (CBO) February 2014 forecast for core inflation is 1.6% to 1.9% in 2014 and 1.8% to 2.2% in 2015.[9] The CBO February 2014 estimate of 2013 core PCE inflation is 1.1%, which is even milder than the February 2013 forecast of 1.5%.[10]

Q. What alternative for establishing non-labor O&M expense for the projected test year do you recommend?

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[8] Minutes of the Federal Open Market Committee March 18–19, 2014, Table 1.
[9] The Budget and Economic Outlook: 2014 to 2024, Table 2-1, inflation forecast for Core PCE price index and Core consumer price index.
[10] February 2013 forecast for core PCE inflation from The Budget and Economic Outlook: Fiscal Years 2013 to 2023, Table 2-1.

A. I recommend adjusting RMP's non-labor O&M expense to remove its projected cost escalation increase for the test period.

Q. Are there any exceptions to your removal of projected inflation from RMP's test period expense?

A. Yes. For a number of line items, such as thermal O&M, wind and hydro O&M, Klamath implementation O&M, Little Mountain expense removal, and regulatory asset amortization expense, RMP has projected test period O&M expense on a standalone basis and compared that result to the inflation-adjusted result (i.e., the base period adjusted actual expense multiplied by the cost escalation factor) for the same line item. The Company then performs an adjustment that effectively replaces the inflation-adjusted line item forecast with the standalone line-item forecast. For these line items, I have not applied my escalation adjustment in order to avoid a potential double-counting of a portion of my adjustment.

Q. Do you believe that RMP is *not* applying an inflation adjustment to these line items?

A. No, not entirely. While RMP appears not to be using the Global Insight inflation forecast for these line items, the Company does escalate monthly line item costs in a manner that suggests that annual cost escalation factors were used. For example, for a number of thermal facilities, constant monthly expense in 2014 is increased discretely in January 2015 and then remains constant for each month thereafter.[11] However, because the Company's cost projections for these line items are associated with specific facilities and may also include operational changes, I am refraining from proposing an inflation removal adjustment to these line items in this proceeding.

Q. What is the impact of your recommended adjustment on Utah revenue requirement?

A. This adjustment is presented in UAE Exhibit RR 1.4. It reduces the Utah revenue requirement deficiency by **$2,444,855**.

GENERATION OVERHAUL EXPENSE – LAKE SIDE 2

Q. Please explain your adjustment to generation overhaul expense for the Lake Side 2 plant.

A. In determining test period generation overhaul expense, RMP uses the normalized cost of generation overhauls over a four-year period, rather than the actual budgeted expense in the test period. For most generating units, RMP uses the most recent four-year historical period, adjusted for inflation, to derive the normalized cost. In this proceeding, RMP uses overhaul expenses for the period July 2009 to June 2013 for this purpose. This normalization approach is used because the generation overhaul schedule for each generating facility follows a multi-year cycle. Consequently, for a given plant, a year in which overhaul expense is particularly great may be followed by years of little or no expense. For

[11] RMP Response to UAE Data Request 13.1, Attachment UAE 13.1.

ratemaking purposes, it is preferable to use a normalization technique for this expense item because the actual overhaul expense in a given test period may not be representative of annual overhaul expense over time. In general, I find the approach used by RMP to estimate its overhaul expense for the projected test period to be reasonable.

For new generating plants, or plants that have not been owned by RMP during the prior four years, there may not be four years of historical overhaul expense data to utilize for normalization purposes. This is the case for RMP's new Lake Side 2 generating plant. For this facility, RMP estimates annual overhaul expense by using four years of *projected* annual costs for the period July 2014 to June 2018.

Conceptually, I do not object to this approach. However, based on my review of RMP's past projections of generation overhaul costs, I have concluded that RMP has tended to overestimate its projected overhaul costs for new plants in rate case proceedings. Consequently, in calculating the four-year average for the Lake Side 2 plant, I have revised downward RMP's projected overhaul expenses for the July 2014 to June 2018 period to adjust for this tendency.

Q. Please explain this adjustment in greater detail.

A. I examined the projections of Currant Creek and Lake Side overhaul expenses for 2007-11 that RMP presented in previous Utah rate cases, Docket Nos. 06-035-21 and 08-035-38. I then compared those projections with the actual overhaul expense incurred by RMP for those years. The comparison is summarized in Table KCH-3, below. It shows that RMP materially overstated its projected overhaul expense for these two plants in those previous rate filings.

Table KCH-3

Currant Creek and Lake Side Overhaul Expenses
Projections vs. Actual

Previous UT Rate Cases
($Constant)

Plant	2007	2008	2009	2010	2011	Average
Currant Creek	3,490,875	1,725,000	7,079,000	1,833,000	1,393,000	3,104,175
Lake Side	1,875,000	650,000	1,818,000	612,000	2,838,000	1,558,600
Total	5,365,875	2,375,000	8,897,000	2,445,000	4,231,000	4,662,775

Actual Costs
($Nominal)

Plant	2007	2008	2009	2010	2011	Average
Currant Creek	1,522,998	1,216,000	5,120,775	410,074	155,629	1,685,095
Lake Side	0	544,000	1,001,480	349,018	4,294,224	1,237,744
Total	1,522,998	1,760,000	6,122,255	759,092	4,449,853	2,922,840

Based on this history, I believe it would be ill-advised to simply accept RMP's overhaul expense projections for its new plant at face value in this proceeding. Accordingly, I have made an adjustment that reduces the Company's projected overhaul expense using a ratio derived from the comparison of the actual Currant Creek and Lake Side costs for 2007-11 to RMP's projections of these costs in the referenced previous Utah rate case. This adjustment factor scales back RMP's projected overhaul expense for Lake Side 2 to 62.7% of the Company's projected cost over the period July 2014 to June 2018.

Q. Do you believe that this type of adjustment is consistent with the guidance the Commission has given with respect to the use of forecasted test periods?

A. Yes. In its test period order issued March 30, 2011 in Docket No. 10-035-124, the Commission approved a test period proposed by RMP that extended 17¼ months beyond the filing date, over the objections of parties that argued for a test period closer in time. In making this decision, the Commission acknowledged that forecast accuracy was an open issue with respect to setting rates using forecasted test periods and stated the Commission's receptiveness to substantiated adjustments to the Company's forecasts when appropriate:

> We note, however, the validity of the Company's forecasts remains to be established on this record. We trust and expect the reservations and even skepticism expressed by some parties will result in thorough evaluation of the Company's cost and revenue forecasts and, where appropriate, the proposal of substantiated adjustments and alternatives. [Order at 8.]

By adjusting for a long-term tendency by the Company to overestimate forecasted generation overhaul expense in rate cases, my approach is consistent with the guidance offered by the Commission.

Q. What is the revenue requirement impact of your adjustment?

A. This adjustment is presented in UAE Exhibit RR 1.5. This adjustment reduces the Utah revenue requirement deficiency by **$161,535**.

GENERATION OVERHAUL EXPENSE – CARBON

Q. Please explain your adjustment to generation overhaul expense for the Carbon Plant.

A. The historical four-year average of generation overhaul expenses used by RMP to depict representative test period costs in this proceeding includes historical costs incurred at the Carbon Plant, which is scheduled for retirement by April 2015, prior to the end of the test period. The average overhaul costs for

Carbon included in RMP's proposed generation overhaul expense is $633,903.[12] This figure reflects a 25% reduction to account for the expectation that Carbon will not be operational for the full test period. However, because the Carbon Plant is being retired, and will not be subject to overhaul expenses either in the test period *or any other future period*, the historical costs of overhauling this plant should not be included *at all* in determining representative overhaul costs for the test period ending June 2015.

Q. What is your recommendation to the Commission?

A. RMP's generation overhaul costs should be adjusted by removing the historical expenses associated with the Carbon Plant. This adjustment is presented in UAE Exhibit RR 1.6. This adjustment reduces the Utah revenue requirement deficiency by **$274,160**.

PENSION EXPENSE

Q. Please explain your adjustment to pension expense.

A. I recommend adjusting the test year level of FAS 87 pension expense to reflect the impact of RMP's revised 2014 plan expense. In its response to UAE Data Request 7.4, RMP provided an updated 2014 electric operations pension expense (i.e., net of mining-related expense) to include the effect of actual 2013 asset and claims experience that became known since the date of the Company's filing. This revision to RMP's 2014 plan expense produces an overall test year

[12] See RMP Exhibit SRM-3, p. 4.8.2.

pension expense amount of $12.6 million, as compared to $14.1 million in the Company's direct filing. RMP's revenue requirement should be based on this more updated information.

Q. Do you have any additional observations regarding RMP's test period pension expense?

A. Yes. RMP's test period straddles the 2014 and 2015 calendar years. The updated pension information that RMP requested from its actuary pertains only to 2014. It seems plausible that the factors causing the reduction in projected 2014 expense would also cause projected 2015 expense to come down, but the Company failed to request the updated information from its actuary that would confirm this assumption.

RMP is not forced to use a test period that extends aggressively into the future: the Company prefers to do so. The Commission should direct the Company that in future rate cases all requests to its actuaries to update pension expense projections should extend through the entirety of the test period that forms the basis of the revenue requirement the Company is seeking.

Q. What is the revenue requirement impact of your recommendation?

A. My recommendation reduces RMP's Utah revenue requirement deficiency by **$214,350**. The impact of this adjustment on net operating income is shown in UAE Exhibit RR 1.7.

POST-RETIREMENT BENEFITS OTHER THAN PENSIONS EXPENSE

Q. Please explain your adjustment to other post retirement benefits – FAS 106 expense.

A. I recommend adjusting the test year level of post-retirement benefits other than pensions ("PBOP") expense to reflect the impact of RMP's revised 2014 plan expense. In its response to UAE Data Request 7.2, RMP provided an updated 2014 electric operations PBOP expense (i.e., net of mining-related expense) to include the effect of actual 2013 asset and claims experience that became known since the date of the Company's filing. This revision to RMP's 2014 plan expense produces an overall test year post retirement benefit-FAS 106 expense amount of $(1.3 million), as compared to $(0.5) million in the Company's direct filing. RMP's revenue requirement should be based on this more updated information.

Q. Do you have any additional observations regarding RMP's test period PBOP expense?

A. Yes. As I noted above, RMP's test period straddles the 2014 and 2015 calendar years. Just as occurred with respect to pension expense, the updated PBOP expense information that RMP requested from its actuary pertains only to 2014. It seems plausible that the factors causing the reduction in projected 2014 PBOP expense would also cause projected 2015 expense to come down, but the Company failed to request the updated information from its actuary that would confirm this assumption.

Just as I am recommending with respect to pension expense updates, the Commission should direct the Company that in future rate cases all requests to its actuaries to update PBOP expense projections should extend through the entirety of the test period that forms the basis of the revenue requirement the Company is seeking.

Q. What is the revenue requirement impact of your recommendation?

A. My recommendation reduces RMP's Utah revenue requirement deficiency by **$123,236**. The impact of this adjustment on net operating income is shown in UAE Exhibit RR 1.8.

LEGAL EXPENSE

Q. Please explain your adjustment to legal expense.

A. The legal expense embedded in RMP's proposed revenue requirement for the test period is based on the Company's actual base period expenses escalated by an inflation factor. As discussed above, I have already removed the inflation factor applied to these expenses. However, a further adjustment is required to remove certain legal expenses incurred by the Company that pertain exclusively to shareholder interests. These legal expenses should not be recovered from customers in rates.

Q. What legal expenses are you recommending be disallowed for recovery because they pertain exclusively to shareholder interests?

A. The expenses concern three cases: (1) USA Power v. Jody L. Williams et al; (2) Deseret Power Electric Co-op (Hunter 2); and (3) Deseret Power Electric Co-op (Turbine).

The USA Power case involves a complaint filed in Utah's Third District Court alleging, among other things, that in developing its Currant Creek generating facility, PacifiCorp breached a confidentiality and non-disclosure agreement with USA Power and misappropriated trade secrets of USA Power.[13] It is my understanding that, on May 21, 2012, a Utah jury found in favor of USA Power and awarded the plaintiff over $130 million in damages, finding, among other things, that PacifiCorp's misappropriation of USA Power's trade secret was "willful and malicious." It is my understanding that these damages have since been modified by the Court to $115 million.[14]

Q. Why are you recommending disallowance of these expenses?

A. There is no stretch of reasoning by which the legal expenses incurred to defend PacifiCorp in the USA Power case can be construed to be a customer responsibility. One of the Utah jury findings against PacifiCorp was that of "unjust enrichment." The cost of defending the conduct of the Company's management against claims of unjust enrichment in a case such as this is entirely a shareholder responsibility. Similarly, the cost to defend against claims of theft or misappropriation should not be borne by ratepayers. Perhaps the Company

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[13] Case No. 050903412.

[14] These figures were reported in PacifiCorp's Form 10-K filing for Dec. 31, 2013, filed March 3, 2014, p. 94.

will argue that, if legal expenses are properly borne by ratepayers, so should the jury's judgment. I cannot conceive of a proper basis for charging ratepayers for damages awarded against the company for theft of trade secrets. For the same reason, PacifiCorp's legal defense in this type of case should not be underwritten by customers under any circumstances.

Q. What is your understanding of the nature of the litigation with Deseret Power?

A. Deseret and PacifiCorp are two of three joint owners of the Hunter Unit 2 power plant that is operated by PacifiCorp pursuant to contract. As I understand it, the contract between Deseret and PacifiCorp requires PacifiCorp to obtain Deseret's consent before making certain capital improvements above a certain cost. In the absence of such consent, PacifiCorp can submit the matter to arbitration and proceed with the capital improvement at its own risk and expense. If the arbitrator determines that the capital improvement was consistent with reasonable utility practice as defined by the contract, Deseret is required to pay its share of the contested capital expenses. If the arbitrator determines that the capital improvement was not consistent with reasonable utility practice, Deseret is not required to pay its portion of the contested expenses.

Q. With respect to the Deseret-related legal expenses that you recommend be disallowed, what capital projects were at issue?

A. As I understand it, there were two separate arbitration hearings involving three capital improvement projects at Hunter Unit 2. The first hearing involved a scrubber upgrade and a conversion of Hunter Unit 2's electrostatic precipitator to a baghouse. The second arbitration hearing involved a turbine rotor upgrade.

Q. What were the results of the arbitration hearings?

A. I understand that the arbitrator in the first hearing found that the scrubber upgrade was not consistent with reasonable utility practice, but that the baghouse conversion was. In the second hearing, my understanding is that the arbitrator found that that rotor upgrade was not consistent with reasonable utility practice. My understanding is that both parties continued to litigate their dispute in court subsequent to the arbitrators' findings.

Q. Have PacifiCorp and Deseret Power resolved their dispute?

A. Yes. Company data responses indicate that a settlement was reached late last year.

Q. Why are you recommending disallowance of the legal costs associated with these disputes?

A. This type of contract litigation with co-owners of a plant is for the benefit or detriment of PacifiCorp and its owners, not its ratepayers. Perhaps the easiest way to illustrate this point is to consider that PacifiCorp's ratepayers do not benefit from a PacifiCorp win in the arbitration or in court – a win simply means that Deseret will pay for a share of the capital costs associated with its ownership in the plant – and PacifiCorp's ratepayers do not suffer if PacifiCorp loses – a loss means that PacifiCorp is required under its operating contract to pay for the co-owner's share of expenditures determined not to be consistent with reasonable utility practice. Capital expenditures associated with an upgrade to a portion of the plant owned by another utility cannot properly be passed on to PacifiCorp's ratepayers. PacifiCorp's ratepayers do not receive value from a portion of the plant owned by another company, and cannot properly be asked to pay capital costs or other expenses associated with that portion. Because ratepayers do not stand to gain or lose from the outcome of this type of litigation, it follows that they cannot properly be expected to pay the legal costs associated with the litigation, regardless of the outcome. To underscore this point, consider that [redacted] This response confirms that the legal expense was incurred solely for shareholder interests.

Q. Are you saying that legal costs associated with litigation with co-owners can never properly be considered in Utah rates?

A. No, any such litigation would have to be evaluated on its own merits under the relevant circumstances. Where, as here, the litigation involves PacifiCorp's alleged contractual failure as operator of a plant to act in a manner consistent with reasonable utility practice vis-à-vis a portion of the plant owned by another

[15] See Confidential Attachment OCS 9.18-1.

company, and where ratepayers do not stand to gain or lose from the outcome, the legal expenses should be borne by PacifiCorp and not its ratepayers.

Q. What is the impact of your recommended adjustment on Utah revenue requirement?

A. This adjustment is presented in Confidential UAE Exhibit RR 1.9. It reduces Utah revenue requirement deficiency by **$1,455,098**.

COLLECTION EXPENSE

Q. Please explain your adjustment to collection expense.

A. RMP included in its revenue requirement costs associated with recovery of unpaid accounts. According to RMP's Response to OCS 4.12, recovery of unpaid accounts is now handled by collection agencies. In its discovery response, RMP indicates that the absence of an adjustment to remove the cost of recovering unpaid accounts was an oversight. This oversight should be corrected by removing these costs from the revenue requirement.

Q. What is the impact of your recommended adjustment on Utah revenue requirement?

A. This adjustment is presented in UAE Exhibit RR 1.10. It reduces Utah revenue requirement deficiency by **$451,308**.

WAGE AND BENEFITS EXPENSE

Q. Please describe your adjustment to RMP's proposed wage and benefits expenses.

A. RMP indicates that its wage and benefits expense for the test period is based on its employee count as of June 2013 of 5,364.5 FTEs.[16] However, as shown in UAE Exhibit RR. 1.11, by September 2013, RMP's FTE count had declined from its June 2013 level by about 30 FTEs and it remained at this lower level through January 2014, before decreasing slightly the following month. It appears that 4 of the 30 FTEs are associated with the facility closure at Little Mountain, which have been taken into account by the Company in its adjustments.[17] Further, it appears that 9 of the 30 FTEs that were reduced subsequent to June 2013 are associated with the Carbon plant, which is scheduled to be retired in April 2015.[18]

I recommend that test period wage and benefits expense be based on the more recent January 2014 FTE level, which better reflects the Company's employment levels than RMP's initial filing. Accordingly, I have reduced test period wage and benefit expense to account for a reduction of 9 FTEs at the Carbon plant and 17 FTEs elsewhere in the Company.

Q. What is the revenue requirement impact of your adjustment to wage and benefits expense?

[16] See RMP Response to MFR R746-700-20.C.3.a and RMP Response to OCS Data Request 4.3.
[17] See RMP Exhibit SRM-3, p. 5.3.
[18] Derived from RMP Responses to UAE Data Requests 6.1(a) and 6.1(b).

A. The resulting impact from my wage and benefits expense adjustment is a **$1,155,605** reduction to Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.12.

CARBON O&M EXPENSE – NON-LABOR

Q. Please describe your adjustment to Carbon non-labor O&M expense.

A. RMP projects that it will incur $4.33 million in non-labor O&M expense at the Carbon Plant during the test period prior to the plant's scheduled retirement in April 2015.[19] Because of that planned retirement, test period O&M expenditures at the Carbon Plant should be viewed as non-recurring in nature and should be removed from base rates, although the Company should still be permitted to recover these costs to the extent they are prudently incurred.

Q. If RMP should still be permitted to recover these costs why should they be removed from base rates?

A. If these costs are recovered in base rates, then they will continue to be charged to customers well after the Carbon plant is retired and they are no longer being incurred, until superseded by rates established in a subsequent rate case.

Q. What ratemaking treatment do you recommend to address this situation?

A. There are two alternatives the Commission can employ in this situation, either of which is reasonable. The first option is to move the test period Carbon non-labor O&M expense from base rates into a rider that would expire after twelve months. This approach would allow RMP to recover its prudently-incurred test period expense while ensuring that these costs do not remain in rates after they are no longer being incurred. The second option is to convert the test period expenses into a regulatory asset and recover them over a specified period

[19] See Exhibit SRM-3, p. 4.9.1.

of time. Carbon-specific deferred accounting treatment has already been established for the purpose of recovering prudently-incurred plant removal costs and for recovering the plant's remaining depreciation balance over the period 2015-2020.[20] The Carbon non-labor O&M expenses could be rolled into a comparable regulatory asset and recovered over the same time period.

Q. What is the impact on base rates of your recommendation?

A. My recommended adjustment to base rates is shown in UAE Exhibit RR 1.13. This adjustment would reduce the Utah revenue requirement reflected in base rates by **$1,912,027**, although these costs would still be recovered from customers through another mechanism as discussed above.

CARBON LABOR EXPENSE

Q. Please describe your adjustment to Carbon labor expense.

A. RMP's proposed revenue requirement includes $6.9 million in labor expense at the Carbon plant during the test period that will be incurred prior to the plant's scheduled retirement in April 2015.[21] These projected costs include the costs of the 9 FTEs that I have removed in my wage and benefits expense adjustment. Because of the planned retirement of the Carbon Plant, the remaining test period labor expenditures at that plant (after the removal of the 9 FTEs) should be viewed as non-recurring in nature and should be removed from base

[20] See Docket No. 11-035-200 et al, Order, Sept. 19, 2012 at 15-16, 28-29.
[21] RMP Response to UAE Data Request 6.1(d).

rates, although, as in the case of non-labor O&M, the Company should still be permitted to recover these costs to the extent they are prudently incurred.

Q. If RMP should still be permitted to recover these costs why should they be removed from base rates?

A. As is the case for non-labor O&M expense, if these costs are recovered in base rates, then they will continue to be charged to customers well after the Carbon Plant is retired and they are no longer being incurred, until superseded by rates established in a subsequent rate case.

Q. What ratemaking treatment do you recommend to address this situation?

A. I recommend adopting either one of the two alternatives I proposed for Carbon non-labor O&M expense: (1) moving the remaining test period Carbon labor expense from base rates into a rider that would expire after twelve months, or (2) converting the remaining test period expenses into a regulatory asset and recovering them over a specified period of time.

Q. What is the impact on base rates of your recommendation?

A. My recommended adjustment to base rates is shown in UAE Exhibit RR 1.14. This adjustment would reduce the Utah revenue requirement reflected in base rates by **$2,489,639**, although these costs would still be recovered from customers through another mechanism as discussed above.

NET POWER COSTS

<u>Third-Party Wind Integration Costs</u>

Q. Does PacifiCorp's OATT include any charges for wind integration services?

A. PacifiCorp's OATT provides for charges for reserves for transmission customers, but it does not provide any charges for wind integration services that are comparable to the wind integration costs included in net power costs and charged to retail customers. Specifically, the OATT does <u>not</u> include any recovery of the opportunity cost of holding back reserves to support wind integration that are recovered in net power costs, but only includes the fixed (capital-related) costs associated with providing wind integration to wholesale customers.[22]

Q. Does RMP charge retail customers for the opportunity cost of wind integration?

A. Yes. These costs associated with wind integration are incorporated into net power costs whenever base net power cost is set in a general rate case. This cost represents the opportunity cost of the capacity that RMP holds back to provide reserves to follow the variations of the Company's wind fleet. That is, when capacity is held back to accommodate the variability in wind, it is not available to make off-system sales. This cost is distinct from the fixed cost of the reserves themselves, which is recovered in rate base. For example, in this case, RMP has included wind integration costs of $14.4 million in net power costs (total Company) to recover this opportunity cost component of wind integration costs.

[22] RMP Response to UAE Data request 3.5.

Q. Did PacifiCorp provide wind integration services to wind projects that do not serve RMP retail load?

A. Yes. During the test period, the Company will provide integration services to several wind projects that do not serve RMP retail load.[23]

Q. How does RMP propose to recover the opportunity costs associated with providing wind integration services to third-party wind projects?

A. The opportunity costs of providing wind integration for these customers are embedded in the net power cost that is projected for the test period. Because these costs are not recovered in PacifiCorp's OATT, the Company is attempting to have retail customers absorb these costs in retail rates. This cross subsidy is both unjust and unreasonable, as the Company should not be allowed to require retail customers to absorb the cost of providing wholesale services to non-retail customers. I recommend adjusting net power cost to assign a pro rata share of wind integration costs to third-party wind facilities.

Q. Have regulators in other states disallowed recovery of opportunity costs associated with third-party wind integration?

A. Yes. The Idaho Public Utilities Commission disallowed these costs and expressly found that "the responsibility for recovery of wind integration costs from wholesale transmission customers resides with the Company, not its retail customers."[24]

[23] See, for example, RMP 2014 GRC Filing Requirement Attachment R746-700-23.C.1-3 CONF.
[24] Idaho Public Utilities Commission Docket No. PAC-E-10-07, Order 32196, Page 30.

Q. Why is the recovery of wind integration costs at issue in this proceeding if RMP already committed to defer Utah's allocated share of the incremental revenues associated with the company's FERC rate case in Docket No. 11-035-200?

A. RMP is obligated, according to Paragraph 51 of the Commission-approved Settlement Agreement in Docket No. 11-035-200 et al, to defer for the benefit of its Utah retail customers any incremental revenues associated with its FERC rate case in Docket No. ER11-3643-000. The FERC rate case was filed on May 26, 2011, and included updated charges for ancillary services, including a new Schedule 3A governing generator regulation and frequency response service. Interim FERC rates went into effect January 1, 2012 and final rates for Schedule 3A were effective March 1, 2013.

However, as discussed above, the rates for this ancillary service do not include the opportunity costs associated with wind integration of the sort that are charged to retail customers. As a result, even though increased revenues associated with Schedule 3A will be deferred and included in the 2013 EBA test period, the deferral will not include opportunity costs incurred in support of wind integration for third-party wind projects.

Q. How did you determine the cost for providing wind integration services to OATT customers?

A. The cost is based on the wind integration costs included in the net power cost proposed by the Company for recovery from Utah retail customers in this proceeding. As shown in RMP's wind integration cost work papers, RMP derives a wind integration cost of $2.03/MWH by calculating the opportunity cost of holding incremental reserves for wind by performing a one-off net power cost run that assumes no wind integration reserves.[25] The $2.03/MWH wind integration cost is derived by spreading this cost across the output from wind resources used to serve retail load *as well as third-party wind*. However, these opportunity costs are absorbed only by the retail load – making the effective cost of wind integration to retail customers actually $2.39/MWH. My wind integration adjustment imputes the $2.03/MWH wind integration cost calculated by RMP to the third-party wind, thus providing a partial offset to the opportunity costs absorbed by retail customers.

Q. What is the revenue requirement impact of your adjustment?

A. This adjustment is presented in Confidential UAE Exhibit RR 1.15. The adjustment reduces the Utah revenue requirement deficiency by **$1,034,310**.

DC Intertie Agreement

Q. Please describe the DC Intertie contract.

A. This contract provides 200 MW of transfer capability to import purchases from the Nevada Oregon Border ("NOB") to PacifiCorp load centers in the Northwest, such as Central Oregon.

[25] See RMP 2014 GRC Filing Requirement Attachment R746-700-23.C.1-3 CONF.

Q. Does the simulation produced by RMP's GRID model indicate that this line will be utilized during the test period?

A. Yes, but only sparingly. According to RMP's response to UAE Data Request No. 4.2, the DC Intertie might be used to deliver [redacted] MWh during the test period. These potential transactions occur in only [redacted] hours out of the 8,760 hours of the test period, or about [redacted] of the time.[26] This usage equates to an average usage of [redacted] MW of the total 200 MW available [redacted].[27] The overall projected average utilization during the test period, including periods of non-use, is [redacted] MW, resulting in an overall utilization of [redacted] of the purchased DC Intertie capacity.[28] The average cost of these deliveries using the test year fixed cost for the DC Interties was in excess of [redacted]/MWh, well over [redacted] times the average embedded retail cost of RMP's transmission service.[29]

Q. Does the GRID model ever utilize the full 200 MW of DC Intertie capacity?

A. Yes, but in only [redacted] hours during the 8,760 hours of the test period.

Q. Does the GRID forecasted usage reflect actual DC Intertie usage?

A. Yes. During calendar year 2013, the primary use of the contract was to facilitate system balancing transactions, but it was utilized only sporadically, and rarely to its full capacity.[30] In response to UAE Data Request No. 4.1, RMP

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[26] [redacted]
[27] [redacted]
[28] [redacted]
[29] [redacted] The average embedded retail cost of RMP's transmission service proposed for recovery in Utah by the Company in this docket is approximately $13/MWh. See RMP Exhibit (JRS-2), p. 7.
[30] Source: RMP Response to UAE Data Request No. 4.1.

identified only [redacted] transactions in 2013 that “could” have utilized the DC Intertie Agreement. These transactions occurred on only [redacted] days out of 365 days during the test period and averaged only [redacted] MW per hour of the total 200 MW contract during hours in which the intertie was actually being utilized. Total deliveries were only [redacted] MWh. This corresponds to an average utilization of less than [redacted] MW over the course of the year, meaning the Company utilized [redacted] of the DC Intertie capacity it purchased.[31] The average transmission cost of these deliveries during 2013, taking into account the test year fixed costs of the DC Intertie contract, would be in excess of [redacted]/MWh, which is [redacted] the average embedded retail cost of RMP’s transmission service.[32]

Q. Did RMP ever utilize the full capacity of its DC Intertie transmission rights during 2013?

A. Yes, but the full 200 MW of transfer capability was utilized for [redacted] during 2013.[33]

Q. What was the original purpose of this contract?

A. My understanding is that the DC Intertie contract was executed in 1994 to provide deliveries of 200 MW of power from Southern California Edison at the NOB. RMP terminated the associated power purchase effective January 1, 2002, but the DC Intertie contract nonetheless remains in effect, although it is seldom used. It costs the Company and its ratepayers [redacted] million per year to purchase

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[31] [redacted] ÷ 8,760 hr) = [redacted] MWh/hr. [redacted] MW/hr ÷ 200 MW/hr = [redacted]

[32] [redacted]

[33] Source: RMP Response to UAE Data Request No. 4.1.

this transmission. My understanding is that the Company has not undertaken any steps to determine if there are options available to renegotiate, modify, terminate or buy out of the contract.[34]

Q. What is your recommended adjustment for the DC Intertie Agreement?

A. I recommend that the Commission disallow recovery of the [redacted] million attributable to the DC Intertie Agreement because the cost is unreasonable in relation to the benefit. As demonstrated above, the contract provides very few benefits in relation to its costs.

Q. What is the revenue requirement impact of your adjustment?

A. This adjustment is presented in Confidential UAE Exhibit RR 1.16. The adjustment reduces Utah revenue requirement deficiency by **$2,002,665**.

<u>Naughton Unit 3 Extended Coal Operations</u>

Q. Please describe your adjustment for Naughton Unit 3 extended coal operations.

A. As discussed in the direct testimony of RMP witness Steven R. McDougal, the Company prepared its revenue requirement under the assumption that Naughton Unit 3 will cease operations as a coal-fired generating unit in December 2014 and will be converted to a gas-fired peaking unit by May 2015. However, the Company is actively seeking to extend the operation timeframe of Naughton Unit 3 as a coal-fired resource from December 31, 2014, to December

[34] Source: RMP Response to UAE Data Request No. 3.2.

31, 2017, and has requested the Environmental Protection Agency to consider such an extension as part of its final action on the Wyoming Regional Haze State Implementation Plan.[35] But because RMP has not yet received regulatory approval for this extension, the lower net power costs associated with the extension are not reflected in the rate filing. RMP indicates that if, prior to the June 4, 2014 rebuttal testimony date in this case, the Wyoming Department of Environmental Quality ("WDEQ") grants the Company's request to amend the Naughton Unit 3 BART permit, the Company will update the revenue requirement request in this case as part of its rebuttal filing. If WDEQ's decision to modify the Naughton Unit 3 BART permit is issued after the rebuttal testimony date, the Company proposes to measure and defer any cost savings from continued Naughton Unit 3 coal operations past December 2014 for future rate making treatment.[36]

I believe this matter should be handled differently. My recommendation is to set base net power costs in the case based on the Company's planned extension of the Naughton Unit 3 coal operations. If, for some reason, the Company's proposed extension is rejected, the incremental costs attributed to that rejection can be deferred for future ratemaking treatment.

Q. What is the revenue requirement impact of your adjustment?

A. This adjustment is presented in UAE Exhibit RR 1.17. The adjustment reduces the Utah revenue requirement deficiency by **$5,206,700**.

[35] See direct testimony of Chad A. Teply, p. 41, 43.
[36] See the transmittal letter accompanying the Net Power Cost Update filed by RMP on April 10, 2014.

PREPAID PENSION ASSET AND OTHER POST-RETIREMENT LIABILITY

Q. What is PacifiCorp's prepaid pension asset?

A. As described in the direct testimony of RMP witness Douglas K. Stuver, 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 expense. In a given year, pension expense differs from cash contributions because pension expense is determined based on accounting guidance while contributions reflect the actual out-of-pocket expenditures in that year. Over the life of a plan, contributions will equal plan expense, but an asset or liability is recorded to account for the timing differences between expense recognition and cash flow. In the case for which cash contributions exceed expense, an asset is recorded (a prepaid pension asset). In the case for which expense exceeds cash funding, a liability is recorded (an accrued pension liability).

Mr. Stuver explains that in recent years, as the result of the Pension Protection Act of 2006 and market conditions, RMP's pension plan contributions have outpaced expense recognized for accounting purposes. RMP projects a 13-month average prepaid pension asset of $312.2 million (total company) for the period ending June 30, 2015.

Q. Does RMP have any accrued liability positions that partially offset the prepaid pension asset?

A. Yes. RMP is in an accrued liability position for its post-retirement benefits other than pensions. As explained by Mr. Stuver, PBOP plans are not subject to the same federal regulations and minimum funding requirements as pension plans, but are subject to IRS funding limits and deductibility rules. As such, PacifiCorp's funding policy for its PBOP plan has been to contribute an amount equal to expense plus estimated Medicare Part D subsidies. However, certain one-time charges were taken several years ago for which no matching contributions were made, resulting in a consistent accrued liability position. PacifiCorp projects a 13-month average accrued other post-retirement liability of $31.2 million (total company) for the period ending June 30, 2015.

Q. How does RMP recover the cost of its pension and other post-retirement plans in Utah?

A. Recovery of pension and PBOP plan expenses are included in RMP's revenue requirement for recovery from customers. However, Utah ratemaking practice does not provide for adjustments to Utah rate base to account for prepaid assets or accrued liabilities that result from net differences between contributions and expense for pension and other post-retirement plans.

Q. What is RMP's proposed ratemaking treatment for its prepaid pension asset and other post-retirement liability in this case?

A. The Company is proposing to drastically change the way prepaid pension assets are treated for ratemaking purposes in Utah by including its prepaid pension asset and accrued other post-retirement liability in rate base, net of ADIT.

According to Mr. Stuver, this treatment is intended to recover prospective financing costs of the net prepaid asset. Based on a 13-month average for the period ending June 30, 2015, the Company's proposal would result in a $162.0 million (total company) net addition to rate base, comprised of the $312.2 million prepaid pension asset and the $31.2 million accrued other post-retirement liability (for a net prepaid balance of $281.0 million), less net ADIT of $119.0 million. For Utah, RMP's proposal translates into a net increase in rate base of $68.8 million.[37]

Q. In your opinion, what is the genesis of RMP's proposal?

A. In 2011, one of the gas utilities in Oregon (Northwest Natural Gas Company) requested recognition of its prepaid pension asset in rate base, which was denied by the Oregon Public Utilities Commission ("OPUC"). However, the OPUC opened a special docket to investigate the matter, Oregon Docket No. UM-1633.[38] As part of that proceeding, five of the Oregon utilities with prepaid pension assets, including PacifiCorp, formulated a common position that advanced Northwest Natural Gas' arguments.[39] Not surprisingly, a sixth utility (Idaho Power), which has a prepaid pension <u>liability</u>, argued for retention of the status quo, i.e., non-recognition of prepaid pension assets or liabilities in its rate

[37] See RMP Exhibit SRM-3, p. 8.03.
[38] The OPUC denied Northwest Natural Gas Company's proposal to include its prepaid pension asset in rate base in Oregon Docket No. UG-221, Order No. 12-408, initiating a generic docket to review the subject.
[39] See the Joint Direct Testimony of Portland General Electric, PacifiCorp, Avista Utilities, Cascade Natural Gas, and NW Natural Gas, filed September 30, 2013, in Oregon Docket No. UM-1633.

base.[40] Now, having staked out a position on this matter in Oregon, RMP argues in this proceeding for the same proposed change in ratemaking treatment in Utah.

Q. What is your assessment of RMP's proposal?

A. I recommend that RMP's proposal be rejected. There are three principal reasons for doing so.

First, RMP's proposal is a prime example of adverse selection, in which the Company's specialized knowledge of its circumstances makes it far more likely to suggest a change in regulatory treatment under conditions in which the change inures to its benefit than when such a change inures to its disadvantage. The evidence is clear on this point. From at least 1998 through 2005, the Company was in an accrued pension <u>liability</u> position which averaged $63 million per year.[41] During those years RMP remained silent on this issue. 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.[42] Now, with the liability having been reversed to an asset, RMP proposes in this proceeding to change the ratemaking treatment. The Commission should be vigilant in fending off selective changes in ratemaking policy that are timed to the Company's advantage.

Second, allowing this change would result in an unreasonable transfer of risk to customers. Utah ratemaking practice provides for recovery of prudently

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[40] See the Rebuttal Testimony of Bruce E. MacMahon, filed March 12, 2014, in Oregon Docket No. UM-1633.
[41] Derived from the information in UAE Exhibit RR 1.18.
[42] RMP Response to UAE Data Request 4.4.

incurred pension expense calculated in accordance with FAS 87. For example, in this proceeding, the basis of RMP's recovery of test year pension costs is the Company's projected FAS 87 accounting expense. Over the life of the pension plan, the sum of FAS 87 pension expense and FAS 88 pension expense (which addresses the termination of the pension plan) equals 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.[43] Rather, 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 expense. The Company claims it is entitled to earn a return on this positive difference – paid for by customers. I disagree.

The existence and size of a prepaid pension asset can be affected by a number of factors, such as discretionary contributions by the Company, the performance in the market of the Company's pension portfolio, and the introduction and enforcement of government regulations regarding minimum contribution amounts, such as occurred with the Pension Protection Act of 2006. I see no reasonable basis for any of these factors to be a cause for customers to be required to pay RMP a return on any prepaid pension asset.

For instance, it should be self-evident that customers should not be held responsible to pay a return to RMP for any discretionary contributions the

[43] 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, in the years ending March 2002 and March 2003, the Company's pension expense was actually negative, but rates to customers were not reduced to reflect this negative expense.

Company makes in excess of its pension expense. Otherwise, such contributions could become a source of open-ended rate base growth, unconstrained by the requirements typically applied to rate base items that such assets be used and useful and their costs prudently incurred. Moreover, it is unreasonable on its face that customers should pay the Company a pre-tax return on equity in the range of 16% in order to fund a pension plan that is projected to earn around 7.5% per year.[44]

Q. Does the current size of RMP's prepaid pension asset appear to be the result of discretionary contributions by the Company in excess of FAS 87 pension expense?

A. No. In fairness, RMP's current situation appears to be driven primarily by a combination of poor portfolio performance during the Great Recession and the effects of new regulations regarding minimum contribution amounts that occurred with passage of the Pension Protection Act of 2006. However, the change in ratemaking policy advocated by RMP in this case makes no distinction between earning a return on a prepaid pension asset that was accumulated as a result of discretionary contributions by the Company versus one that was caused by contributions triggered as a consequence of poor portfolio performance.

Q. Please continue explaining your assessment of the Company's proposal.

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[44] The January 2014 Towers Watson Actuarial Valuation Report (provided in RMP's Response to OCS 3.16, Attachment OCS 3.16-3) assumes an expected long-term return on plan assets of 7.50%. The pretax return on equity requested by RMP in this case is 16.1%.

A. As I stated above, the existence and size of a prepaid pension asset can be affected by the performance in the market of the Company's pension portfolio, as well as the introduction and enforcement of government regulations regarding minimum contribution amounts. For instance, if the Company's pension portfolio suffers poor or negative returns, as occurred during the Great Recession, then Federally-required minimum contributions to ensure plan solvency can cause cumulative contributions to exceed cumulative FAS 87 pension expense. Paradoxically, *above-normal* returns can *also* cause prepaid pension assets to increase, because above-normal returns can cause FAS 87 pension expense to be negative; mathematically, a negative pension expense will always cause the amount of the prepaid pension asset to increase – even if contributions are zero.

Requiring customers to pay a return on the prepaid pension asset is unreasonable in either of these two scenarios. If the underlying cause is poor performance of the pension portfolio, then requiring customers to pay a return on the excess contributions required to bring the plan into compliance with federal funding requirements is tantamount to having customers backstop the performance of the Company's plan in the stock market. This is an unreasonable transfer of business risk to customers. Customers already fund the pension plan over the course of its life. The risk that the pension plan may underperform in the market and require enhanced contributions by shareholders for a period of time is a business risk facing every major corporation in the country with a defined benefit plan. For RMP, whose customers ultimately fund the plan, this risk amounts to managing a timing difference, a risk which currently rests with shareholders and with whom properly it should remain. The Commission should not allow RMP to shift this burden to customers. In Utah, utility management is expected to cope with normal business risks and the operation of economic forces.[45]

Requiring customers to pay a return on the prepaid pension asset is also unreasonable for the scenario in which a prepaid pension asset increases due to above-normal performance of the pension portfolio. In this case, the prepaid pension asset can increase even if Company contributions are zero because the above-normal performance results in negative FAS 87 pension expense. Thus, the prepaid pension asset increases largely due to investment returns; although these returns may produce a future benefit to customers by reducing future pension expense, requiring customers to pay RMP a return on the asset balance would result in an increase in rate base due to the market performance of the pension portfolio as opposed to increased contributions by the Company.

Q. Aside from management's responsibility to cope with normal business risks and the operation of economic forces are there additional reasons that the risk of managing the timing difference should remain with shareholders?

[45] See for example, Report and Order, 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, March 4, 1999 at 47-48.

A. Yes. MidAmerican Energy Holdings Company ("MEHC") purchased PacifiCorp in 2006[46] with the full knowledge that the ratemaking practice in Utah (and other PacifiCorp states) did not provide for an adjustment to rate base for prepaid pension assets or liabilities. In purchasing PacifiCorp, MEHC took on the Company's pension obligation and the timing risks associated with funding it. This risk should have been reflected in the purchase price of the Company. Although the Pension Protection Act of 2006 had not yet passed at the time of MEHC's acquisition of PacifiCorp, pension reform policymaking was already underway. In January 2005, the Bush Administration advanced a pension funding reform proposal and the final legislation retained the policy goals and basic structure of that proposal.[47] Moreover, the fact that PacifiCorp's pension plan was underfunded at the time of its acquisition by MEHC was expressly acknowledged by the Commission in its order approving the acquisition in Docket No. 05-035-54.[48] Having purchased PacifiCorp with knowledge of the potential timing risks for funding the Company's pension obligation, it would be unreasonable to shift this risk now from MEHC to customers.

Q. What is the third reason for rejecting RMP's proposal?

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[46] MEHC's purchase of PacifiCorp was completed March 2006, based on an agreement reached in May 2005.

[47] According to a Congressional Research Service Report to Congress (Oct. 23, 2006), in January 2005, the Bush Administration advanced a proposal for pension funding reform, designed to increase the minimum funding requirements for pension plans and strengthen the pension insurance system. Subsequently in 2005, Senator Charles Grassley introduced S. 1783, the Pension Security and Transparency Act, and Representative John Boehner introduced H.R. 2830, the Pension Protection Act, which was renumbered as H.R. 4. The legislation ultimately passed and signed into law by President George W. Bush on August 17, 2006 was based mainly on these two bills.

[48] Docket No. 05-035-54, Report and Order at 12.

A. There is a material issue of notice and retroactivity to consider in this matter. As shown in UAE Exhibit RR 1.18, RMP's prepaid pension asset has been built up over the past eight years since the Company's prepaid pension liability crossed over to an asset in 2006. Since that time, six general rate cases have been conducted in Utah and correspondingly Utah rate base has been approved six times without the inclusion of the prepaid pension asset. This proceeding is the first case in which RMP has provided notice to parties and the Commission that Company believes it is entitled to earn a return on the prepaid asset balance. It is not reasonable for this $162 million rate base claim to appear as if the cost was somehow incurred since the last rate case. Allowing this amount into rate base now would be analogous to *removing* items from rate base today that had been approved in years past and for which functionality had not changed. It would invite significant regulatory uncertainty.

Q. Please summarize your recommendation to the Commission on this matter.

A. I recommend that RMP's proposal to include its prepaid pension asset in rate base be rejected. From a process standpoint, the Company's proposal suffers from being a prime example of adverse selection, in which the Company's specialized knowledge of its circumstances makes it far more likely to suggest a change in regulatory treatment under conditions in which the change inures to its benefit than when such a change inures to its disadvantage. The Company's proposal also raises serious concerns with respect to notice and retroactivity. But even more importantly, adoption of RMP's proposal would result in an unreasonable transfer of risk to customers.

Q. What is the revenue requirement impact of your recommendation?

A. The resulting impact from my adjustment is a $**7,493,354** reduction to Utah revenue requirement deficiency. This adjustment is shown in UAE Exhibit RR 1.19.

Q. Your recommendation to reject the Company's proposal notwithstanding, do you have any further recommendations in the event the Commission finds some recognition of RMP's claim is warranted?

A. Yes. Although I firmly believe the Company's proposal should be rejected in its entirety, in the event the Commission approves some version of RMP's proposal, it would be necessary to modify the proposal to protect the public interest. First, if a return is allowed on prepaid pension assets, then the addition to rate base should be limited to *changes* in the amount of the prepaid pension asset on a *going-forward* basis. This limitation would address the notice and retroactivity concerns discussed above in my testimony. Second, the allowed pre-tax return on RMP's prepaid pension asset should be capped at the long-term return on the pension assets that is used in calculating the Company's pension expense.

Q. Please explain this last point.

A. As noted above, the projected long-term return on RMP's pension plans is 7.5 percent. In contrast, the cost to customers of paying RMP its pre-tax rate of return on its prepaid pension asset (at RMP's requested rate of return) is 10.9 percent. In a ratemaking sense, when RMP's contributions exceed its pension expense, the Company is attempting to force customers to borrow from RMP at 10.9 percent so that the proceeds can be invested in RMP's pension plans at 7.5 percent. Even though the funds invested at 7.5 percent produce future returns, the upfront cost is clearly too high: borrowing at 10.9 percent in order to invest at 7.5 percent obviously is not a good proposition for the borrower. Indeed, if a prepaid pension asset were to be included in rate base, it would be unreasonable for customers to pay anything more to RMP for use of this asset than the long-term return on RMP's pension plans. Making this adjustment would mean capping the pre-tax rate of return on the prepaid pension asset at 7.5 percent.

CONTINGENCY RESERVE COSTS

Q. Does RMP include a contingency amount when estimating plant additions in a future test period?

A. Yes. According to RMP's Response to UAE 11.1, the Company includes contingency costs on certain projects costing more than $10 million.

Q. How does RMP determine what amount of contingency cost to include when estimating the cost of plant additions?

A. According to RMP's Response to UAE 11.4, when necessary, project cost estimates include a contingency estimate to reflect identified risks such as the length of the construction period; the complexity associated with the project; and unforeseen and unpredictable conditions, such as weather and soil conditions, and uncertainties within the defined project scope such as commodity prices.

Q. Do you have any concerns regarding the inclusion of contingency costs in rate base when using a projected test period?

A. Yes, I do. One of the challenges in using a projected test period is to ensure that the amount of projected plant additions is accurate. This challenge can be exacerbated when projections of plant additions include a contingency factor. Including a contingency factor may make sense when managing a construction budget for any particular project; however, it does not necessarily follow that including the sum of contingency costs for all major projects is reasonable from a ratemaking perspective. It is one thing to have some room in the construction budget for a given project in case something goes wrong; it is another thing to charge ratepayers for projected rate base that assumes that something goes wrong for every major project that is carrying a contingency component. To do so is to ensure that customers are overcharged.

Q. Are you recommending an adjustment for contingency costs?

A. Yes. For purposes of this case, I am recommending a conservative adjustment applicable only to contingency costs that were included in the Company’s filing, but which since have been adjusted downward based on the Company’s actual experience since the filing date. RMP identified these updates in its Response to UAE Data Request 11.8. My adjustment incorporates a reduction in depreciation expense and a reduction in 13-month average rate base associated with the contingency reserve reductions identified by RMP in the aforementioned data response.

This adjustment does not address my larger concerns about the inclusion of contingency costs in rate base in the first instance. As a matter of ratemaking policy, the Commission should consider excluding projected contingency reserve costs from rate base for new plant when using a projected test period. If completion of the project ultimately requires the use of contingency costs, the added costs can be included in rate base as part of the next rate case to the extent they were prudently incurred.

Q. What is the impact of your adjustment on the Utah revenue requirement?

A. This adjustment is presented in UAE Exhibit RR 1.20. It reduces the Utah revenue requirement deficiency by approximately **$187,417.**

Q. Does this conclude your direct testimony?

A. Yes, it does.