Witness OCS – 3D

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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| **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** | )<br>)<br>)<br>)<br>)<br>)<br>) | **Docket No. 11-035-200**<br><br>**Direct Revenue Requirement Testimony of Donna Ramas For the Office of Consumer Services** |

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CONFIDENTIAL INFORMATION REDACTED

June 11, 2012

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**INTRODUCTION**

**Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?**

A. My name is Donna Ramas. I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory analyst at Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

**Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.**

A. Larkin & Associates, PLLC, is a Certified Public Accounting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates, PLLC has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including numerous electric, water and wastewater, gas and telephone utility cases.

**Q. HAVE YOU PREPARED AN EXHIBIT SUMMARIZING YOUR QUALIFICATIONS AND EXPERIENCE?**

A. Yes. I have attached Appendix I, which is a summary of my regulatory experience and qualifications.

**Q. ON WHOSE BEHALF ARE YOU APPEARING?**

A. Larkin & Associates, PLLC, was retained by the Utah Office of Consumer Services (OCS) to review Rocky Mountain Power's (the Company or RMP) application for an increase in rates in the State of Utah and to make recommendations in the areas of rate base and operating income (expense and revenue). Accordingly, I am appearing on behalf of the OCS.

**Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?**

A. Yes. I have prepared Exhibits OCS 3.1D through 3.20D, which are attached to this testimony.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. I present the overall revenue requirement recommended by the OCS and sponsor specific adjustments to the Company's filing for the future test period ending May 31, 2013. The overall revenue requirement presented in the summary schedules, specifically Exhibits OCS 3.1D and OCS 3.2D, includes the impact of recommendations of other witnesses testifying on behalf of the OCS. It includes the recommended return on equity and capital structure presented by OCS witness Daniel Lawton, as well as specific adjustments recommended by OCS witnesses Michele Beck and Randall Falkenberg.

**Q. PLEASE DISCUSS HOW YOUR EXHIBITS ARE ORGANIZED.**

A. Exhibit OCS 3.1D presents the overall revenue requirement and summary schedules. Each of the pages in Exhibit OCS 3.1D is based on the 2010 Protocol allocation method.

In preparing Exhibit OCS 3.1D, I used the Company's Jurisdictional Allocation Model, flowing each of the OCS recommended adjustments through the model.

**Q. PLEASE DESCRIBE THE ORGANIZATION OF THE REST OF YOUR EXHIBITS.**

A. Exhibit OCS 3.2D includes a summary schedule that lists all of the OCS recommended adjustments in one schedule on a Utah basis using the 2010 Protocol allocation factors calculated by RMP in its filing. While I am recommending an adjustment that impacts the allocation factors in this case, Exhibit OCS 3.2D was calculated based on RMP's proposed allocation factors for ease of comparison. The full revenue requirement impact will not tie directly into the summary schedule on Exhibit OCS 3.1D as the amounts on this schedule do not include the cash working capital impact and interest synchronization impact of each of the adjustments. Those impacts flow automatically through the Jurisdictional Allocation Model. Exhibit OCS 3.2D also excludes amounts that are considered confidential as well as the impact of the change in the allocation factors which flow through the Jurisdictional Allocation Model.

Exhibits OCS 3.3D through 3.19D, consist of the supporting calculations for the specific adjustments that I recommend the Commission adopt. These supporting exhibits are presented using the top-sheet approach, showing the specific adjustments on a total Company and Utah allocated basis with brief descriptions of the adjustments at the bottom of each exhibit.

In determining the Utah allocated impact of each adjustment presented in Exhibits OCS 3.2D through 3.19D, as well as the discussion in this testimony of the Utah impacts of the individual adjustments, the jurisdictional allocation factors contained in Company Exhibit RMP__(SRM-3) are used so that the adjustments are comparable to the basis presented by the Company in its exhibits. The impact of the OCS' recommended adjustment impacting the jurisdictional allocation factors discussed later in this testimony is incorporated in the Jurisdictional Allocation Model used in determining the overall revenue requirement presented in Exhibit OCS 3.1D.

Exhibit OCS 3.20D consists of a press release and a Special Verdict Form from a legal matter discussed later in this testimony.

**Q. BASED ON THE OCS' ANALYSIS OF ROCKY MOUNTAIN POWER'S FILING, WHAT IS THE OCS' RECOMMENDED CHANGE TO THE CURRENT LEVEL OF UTAH REVENUE REQUIREMENT?**

A. Rocky Mountain Power's filing shows a requested increase in revenue requirement of $172,267,339 based on the 2010 Protocol allocation method[1]. Based on the OCS' analysis, the Company's request is significantly overstated by an amount of $98,861,579. As shown on Exhibit OCS 3.1D, page 1 of 3, the Office of Consumer Services recommends an increase in the current level of Utah revenue requirement of $73,405,760.

**Q. IN WHAT ORDER WILL YOU PRESENT YOUR RECOMMENDED ADJUSTMENTS TO ROCKY MOUNTAIN POWER'S REQUEST?**

A. I first present my recommended rate base adjustments. I then discuss the recommended modification that impacts the jurisdictional allocation factors in this case, followed by recommended adjustments to net operating income.

[1] Consistent with the 2010 Protocol Agreement, the Hydro Endowment and Klamath adjustments called for in the 2010 Protocol have been zeroed out. Thus, the results are the same under either the 2010 Protocol or the Rolled In allocation methods for Utah.

## RATE BASE ADJUSTMENTS

**Q. WHAT ADJUSTMENTS TO RATE BASE DO YOU SPONSOR?**

A. First, I am sponsoring adjustments to RMP's projected pro forma plant additions for the Casper Service Center and the Lakeside II Interconnection project along with the associated impact on accumulated depreciation; cash working capital; and accumulated deferred income taxes. I also present the impacts of Ms. Beck's recommended removal of the Klamath settlement costs and accelerated depreciation of the remaining Klamath net plant balance.

### Casper Service Center Buy-Out

**Q. ARE THERE ANY PLANT ADDITIONS INCLUDED IN THIS CASE WHICH ARE ALLOCATED TO THE UTAH JURISDICTION THAT SHOULD NOT BE?**

A. Yes. Exhibit RMP__(SRM-3), at page 8.6.27, identifies a project titled Casper Service Center Lease Buy-Out at a cost of $2.95 million. OCS Data Request 8.26 asked what the project was for and why the amount added to plant for this project was being allocated to Utah using the SO factor. In response the Company indicated, in part, that the Casper Service Center Lease Buy-Out project should have been assigned to Wyoming and not allocated based on the SO factor. As part of the response, RMP indicated that the estimated project costs would be replaced with actual costs and assigned to Wyoming in its rebuttal filing.

**Q. ARE YOU RECOMMENDING ANY ADJUSTMENT AT THIS TIME ASSOCIATED WITH THIS PROJECT?**

A. Yes. On Exhibit OCS 3.3D I provide the adjustment needed to remove this project from the test year as it should not be allocated to the Utah jurisdiction. As shown on this exhibit, test year plant in service allocated under the SO allocation factor should be reduced by $2.95 million on a total Company basis and $1,264,193 on a Utah allocated basis. Based on the composite depreciation rate contained in the filing for General Office plant allocated using the SO factor of 6.44%, depreciation expense should be reduced by $189,980 ($81,414 Utah basis). The average test year accumulated depreciation balance should be reduced by $174,148 ($74,629 Utah), which is calculated based on the 6.44% depreciation rate and RMP's assumption used in the filing that it would be placed into plant in service in December 2011.

**<u>Lake Side II Interconnection Transmission Plant</u>**

**Q. SHOULD ANY FURTHER PROJECTED PLANT ADDITIONS BE REMOVED FROM PLANT IN SERVICE IN THIS CASE?**

A. Yes. I recommend that the amount the Company incorporated in the filing under the transmission plant additions for the Lake Side II Interconnection

Project be removed. At page 21 of his direct testimony, Company witness Darrell Gerrard indicates that this project is for the construction of a new 345 kV point of interconnection substation to interconnect the Lake Side II generation facility into the existing 345 kV Camp Williams-Hunter/Emery transmission line. Mr. Gerrard also indicates at pages 21 and 22 of his testimony that PacifiCorp Energy, an affiliated entity, is the interconnection customer and that the interconnection must be completed by May 1, 2013 to "…provide electrical back feed approximately one year ahead of the generation plant in-service date." RMP has included $19,233,313, the projected costs of the transmission interconnection expected to be placed in service in May 2013, in Exhibit RMP__(SRM-3), page 8.6.24. Since the project is reflected as being added in the final month of the test year, the impact on the average test year plant in service balance associated with this project is an increase of $1,479,486. I recommend that this amount be removed from test year plant in service in this case.

**Q. WHY DO YOU RECOMMEND THAT THESE COSTS BE REMOVED FROM THE TEST YEAR IN THIS CASE?**

A. Utah ratepayers will not begin to receive a benefit from this interconnection until such time that the Lake Side II generation facility is placed into service and is being used and useful in providing energy to customers. In response to OCS Data Request 6.18(b), RMP indicated that the interconnected facilities will be used and useful to customers in advance of the generation plant being placed into service "…because these transmission facilities are necessary to provide electrical service necessary for final construction, testing, control and start up of the plant." I disagree that this qualifies as being used and useful in the provision of service to customers and recommend that the interconnection facility cost not be placed into rate base until such time as the Lake Side II facility is used and useful in serving customers in Utah. In response to OCS Data Request 6.18(a), the Company indicated that the anticipated in-service date for the Lake Side II plant is not until June 2014, which is more than a year beyond the end of the test year in this case.

**Q. WHAT ADJUSTMENT IS NEEDED TO REFLECT YOUR RECOMMENDED REMOVAL OF THE LAKE SIDE II INTERCONNECTION PROJECT FROM RATE BASE?**

A. As shown on Exhibit OCS 3.4D, average test year plant in service should be reduced by $1,479,486 ($638,472 Utah). Similarly, depreciation expense should be reduced by $15,148 ($6,537 Utah), accumulated depreciation should be reduced by $1,165 ($503 Utah), and accumulated deferred income taxes should be reduced by $34,651 ($14,954 Utah). Each of these amounts was provided by the Company in its response to OCS Data Request 6.18(d).

**<u>Cash Working Capital – Lead/Lag Study</u>**

**Q. COULD YOU BRIEFLY DESCRIBE WHAT CASH WORKING CAPITAL IS AND WHY IT IS INCLUDED IN RATE BASE?**

A. Yes. Cash working capital is an amount of cash a company needs to have on-hand in performing its day-to-day operations. A good description is provided in the introduction section of the Company's lead/lag study filed in this case, at page 1.1, as follows:

> In this NOPR, FERC indicates that cash working capital is the amount of cash needed on-hand by a public utility to pay its day-to-day operating expenses, for the time period during which the utility has provided electric service to its customers and has not yet received payment for that service. If, on average, the time difference between providing service and collecting the associated revenue exceeds the time difference between providing service and paying the associated expense, the utility experiences a "net revenue receipt lag." This requires funding a working cash balance. On the other hand, if the lag in payment of expenses is longer than the lag in collection revenues the utility experiences a "net expense payment lag," meaning the collection of revenues occurs in advance of paying expenses. A utility experiencing a "net revenue receipt lag" requires working cash in its revenue requirement.

In other words, a cash working capital requirement could be either positive or negative depending on the lag calculation specific to a company. If, on average, the expenses need to be paid prior to revenues being received, then the resulting positive cash working capital requirement is funded by the Company's investors. Under that situation, the cash working capital requirement is added to rate base to allow a return to be earned on the provision of those funds. However, if the opposite occurs and the company receives its revenues in advance of needing to pay its expenses, then a cost-free source of capital results that is used to offset rate base.

**Q. DID THE COMPANY PROVIDE A NEW LEAD/LAG STUDY IN THIS CASE FOR THE PURPOSES OF CALCULATING THE CASH WORKING CAPITAL TO BE INCLUDED IN RATE BASE?**

A. Yes. In Filing Requirement R736-700-22.D.43 the Company provided a new lead/lag study along with some of the supporting workpapers for that study that were used to calculate the cash working capital in this case. This lead/lag study was calculated using 2010 data. The results of the 2010 lead/lag study show a revenue lag for the Utah jurisdiction of 40.76 days and a total expense lag of 35.84 days, resulting in net lag days for Utah of 4.92 days. The resulting net lag days of 4.92 days are then applied to the Company's average daily cost of services to obtain the amount of cash working capital that is added to rate base. In Exhibit RMP__(SRM-3), pages 8.1 and 8.1.1, the Company shows the impact of applying the 4.92 net lag days to the adjusted average daily amount for expenses[2] incorporated in its filing, resulting in its adjusted test year cash working capital request of $18,657,920. This amount is on a Utah specific basis. The application of the net lag days to the average daily expenses is included as an automatic calculation within the Company's Jurisdictional

[2] The expenses the lag is applied to includes O&M expense, taxes other than income and the portion of the Federal and State income taxes identified as current.

Allocation Model in this case. Within that model there is a section in which the Utah revenue lag days and Utah expense lag days are inserted resulting in the net lag days. The resulting net lag days are automatically applied to the average daily expense contained within the model.

**Q. DO YOU HAVE ANY CONCERNS WITH THE LEAD/LAG STUDY PRESENTED BY THE COMPANY WHICH NEED TO BE ADDRESSED?**

A. Yes. Based on a review of the 2010 lead/lag study as well as the responses to several data requests directed at that study, I am recommending several revisions to the Company's calculation of the net lag days. First, I recommend that the net revenue lag for Utah be reduced by one day to shorten the billing lag that is incorporated in the 2010 lead/lag study. I am also recommending several modifications to the calculation of the "Other O&M Expense" lag, which impacts the total expense lag, to address several significant problems with the method used by the Company in its study.

**Q. SINCE YOU ARE RECOMMENDING THAT THE REVENUE LAG DAYS BE REDUCED, WOULD YOU PLEASE FIRST DESCRIBE THE COMPONENTS THAT ARE USED TO CALCULATE THE REVENUE LAG DAYS?**

A. Yes. The revenue lag is made up of three separate components consisting of the service lag, the billing lag and the collection lag. As an example, I will discuss the Company's calculation of the revenue lag for the General Business Revenues category. For this category of revenues, the service lag used by the Company in its analysis is 15.2 days and consists of the average time period between when the customer begins receiving service for a billing cycle and when the customers' meter is read. Given that service is typically provided for and billed on a monthly basis, the average service lag is 15.2 days.

The billing lag is the period between the date the meter is read and when the invoice is processed in the Company's billing system. The Company's billing lag is presented on page 3.2 of its 2010 lead/lag study, showing a billing lag during 2010 of 2.88 days on average. The amount of billing lag days per month used in deriving that average varies from a high of 3.25 days in January 2010 to a low of 2.15 days in December 2010.

The final component of the revenue lag calculation is the collection lag which is the difference between the invoice date and the date, on average, that a customer pays for service, which was calculated by RMP to be 23.91 days for General Business Revenues. Combining the three separate components, that being the service lag, the billing lag and the collection lag, the result is revenue lag of 42.00 days for General Business Revenues.

**Q. HAVE ANY CHANGES BEEN MADE TO THE COMPANY'S REVENUE BILLING PROCESS THAT WOULD IMPACT THE LAG DAYS CALCULATED IN THE 2010 LEAD/LAG STUDY?**

A. Yes. Since the lead/lag study is based on 2010 data, the billing lag used by the Company in its analysis would not yet fully reflect the implementation of automated meters in Utah.

**Q. WOULD YOU PLEASE DISCUSS THE IMPLEMENTATION OF AUTOMATED METERS IN UTAH AND HOW THAT WOULD IMPACT THE REVENUE LAG CALCULATION?**

A. The Company began installing automated meters in Utah in mid 2009 with implementation occurring over a number of years. In the prior rate case, Docket No. 10-035-124, Company Exhibit RMP__(SRM-3), at page 4.13, indicates that beginning in November 2009 the Company completed 9,452 new automated meter installations in Tremonton and Laketown Districts, and that in March 2010 the Company <u>began</u> the installation of approximately 29,327 automated meters in the Cedar City and Smithfield districts. Additionally, the current filing, in Exhibit RMP__(SRM-3), at page 4.11, indicates that the Company began installing 33,396 meters in August 2011 for the remaining Utah service territory. The lead lag analysis was based on 2010 data, and while the Company had begun implementation of the automated meters in mid-2009, the automated meters had not been fully implemented in Utah during the period considered in the lead/lag study. The implementation of automated meters would serve to reduce the billing lag in that the billing information would be sent automatically to the Company's billing system and the need to manually read the meters is eliminated. This would reduce the average amount of lag days which were calculated to be 2.88 in the 2010 lead/lag study. .

**Q. WHAT ADJUSTMENT DO YOU RECOMMEND TO THE REVENUE LAG DAYS IN THIS CASE?**

A. I recommend that the revenue lag days be reduced by one day. The Company should be able to realize efficiencies in the billing process and a reduction in the billing lag days as a result of the full implementation of automated meters in Utah. These additional efficiencies would not be fully reflected in the 2010 lead/lag analysis. As the costs of the automated meters are included in plant in service in this case, and the Company is making an adjustment to reflect additional cost reductions as a result of implementing those meters, the impact on the revenue lag days should also be acknowledge in this case. Consequently I recommend that the revenue lag days incorporated in the Company's analysis of 40.76 days be reduced by one day to 39.76 days.

**Q. COULD YOU PLEASE NOW DISCUSS YOUR CONCERN WITH THE OTHER OPERATIONS & MAINTENANCE LAG DAYS INCLUDED IN THE COMPANY'S LEAD/LAG STUDY?**

A. There are several significant problems with the Company's calculation of the lag days for the Other Operations & Maintenance category in the lead/lag study. The Company used the Other Operations & Maintenance lag for all remaining O&M expenses that do not fall into the separate expense categories which the Company used to calculate specific lag days. For example, the Company has calculated coal expense lag days, natural gas purchase lag days, purchase power lag days, and labor and benefit expense lag days. All O&M expenses that do not fall into categories that are being specifically calculated elsewhere in the lead/lag analysis are included in the Other Operations & Maintenance category. However, there is a significant flaw in the method used by the Company in calculating that Other Operations & Maintenance lag days.

Basically, the Company used an extremely simplistic approach in which it began with the monthly accounts payable balances. The Company removed items that fall into the expense lag categories that it separately accounted for in its lead/lag study as well as payables associated with retention hold outs on capital projects. However, all of the remaining items on the account payable reports were used in the analysis in which the Company calculated the lag days as the difference between the check cash date for the invoice and the date of the invoice. In other words, the Other Operations & Maintenance lag calculation is based on a vast range of payables recorded on the Company's books with the lag calculated as the difference between the date on the invoice for the cost and the date that the cash was cleared.

Under the method used by the Company, there are two key flaws. The first is that there is no consideration of the service lag associated with the costs included in the study. The second significant flaw is that there are some significant costs that pertain to capital items, not O&M expense on the Company's books and records. Capital items are already included in rate base to earn a return and should not be included in calculating the lag to apply to O&M expenses in determining the amount of cash working capital to include in rate base.

**Q. PLEASE DISCUSS THE FIRST ISSUE YOU RAISED PERTAINING TO THE SERVICE LAG.**

A. The Company's method of beginning the calculation of the lag days with the invoice date is overly simplistic and assumes that the Company received the benefit of the services or the items that are being expensed on the date the invoice was prepared by the vendor. This is not a reasonable or realistic assumption. There are many types of costs incurred by a company that would be recorded in operation and maintenance or administrative and general expenses (i.e., remaining expenses falling in the "Other Operations & Maintenance" category in the lead/lag study) for which the service may be provided over an extended period of time. For example, for the consulting services received by the Company, it is likely that those services would be billed on a periodic basis, such as a monthly basis. It may also be likely that the invoice date associated with those services would not be dated the very date that the service was completed. For example, if one were to assume that the external auditors bill on a monthly basis, the service lag would be 15 days for the month average service period. Similarly, those external auditors may also wait several days to prepare and issue the invoice after month end.

In calculating another lead/lag category in its 2010 lead/lag study, specifically the purchase power lag, PacifiCorp included 15.2 days for the product lag to account for the fact that the receipt of energy was assumed to occur evenly throughout the end of the month. The Company did not make any sort of similar assumptions or analysis with regards to the Other Operations & Maintenance category and instead just assumed that the lag would begin with the invoice date.

**Q. HOW DO YOU SUGGEST THIS PROBLEM BE REMEDIED?**

A. I recommend that the calculated Other Operations & Maintenance lag days be increased by seven (7) days. It is my opinion that an assumption of seven service lag days is a conservative estimate as many expenses and services are provided over a monthly period and an average monthly service period would be 15 to 15.2 days. However, absent the amount of time that would be needed to conduct a detailed lag analysis for the expenses falling into the Other Operations & Maintenance category, a seven day lag is a reasonable assumption at this time.

**Q. WHAT IS YOUR NEXT MAJOR AREA OF CONCERN WITH REGARDS TO THE METHOD BY WHICH THE COMPANY CALCULATED THE LAG DAYS FOR THE OTHER OPERATIONS & MAINTENANCE CATEGORY?**

A. The method used by the Company is not in any way limited to the expenses that fall within the category. In fact, it is not even limited to expense items, but also include capital costs. In response to DPU Data Request 24.5, the Company provided its detailed workpapers for calculating the lag days for the Other Operations & Maintenance category. Also, in response to DPU Data Request 24.11, the Company provided additional information on some specific items included in the Other Operations & Maintenance lag day calculations. Based on the review of these two responses, it is clear that the Company has included some significant costs that are capital in nature and not expenses.

As an example, for the month of January 2010, the following invoices were included in the Other Operation & Maintenance lag calculation:

- $7,109,555 for a payment on the Dave Johnston Flue Gas Desulfurization Project;
- $4,779,410 for a payment on a high-intermediate and low pressure steam turbine retrofit project at the Huntington Plant;
- $6,888,509 associated with a transmission line capital project; and
- $27,367,030 associated with the Populus - Terminal 345kV transmission line project.

**Q. HOW DO YOU RECOMMEND THAT THE SIGNIFICANT FLAWS WITH THE OTHER OPERATIONS & MAINTENANCE LAG DAYS CALCULATION BE ADJUSTED IN THIS CASE?**

A. I am recommending two adjustments. First, I recommend that all amounts exceeding $2 million that were included in the Company's Other Operations & Maintenance lag day calculations be removed from the analysis. Based on the information I have been able to review to date, it appears that the majority of the items exceeding $2 million are related to capital projects which clearly should not be included in the Other Operations & Maintenance lag day calculations. The impact of including the projects over $2 million is a reduction in the Other Operations & Maintenance lag days which causes the cash working capital request to be higher than would otherwise be the case had these projects been excluded from the analysis.

**Q. HOW DID YOU QUANTIFY THE IMPACT OF THIS RECOMMENDATION?**

A. Using the Other Operations & Maintenance lag day workpapers that were provided by the Company in response to DPU Data Request 24.5, I removed all items from each month of the Company's analysis that exceeded $2 million. In doing this analysis, I was careful to insure that items exceeding $2 million in which the Company reflected both a credit and debit within the month were removed from both sides of the entry. For example, if a $2 million item was recorded in the month and shown in the workpapers, but a credit for the exact same amount was shown in the Company's workpapers for the same item I removed both sides of the entry. I am providing my workpapers calculating this adjustment separately with this testimony. Again, in calculating the amounts I used the workpapers provided by the Company in response to the DPU Data Request 24.5 for the Other Operations & Maintenance lag days and removed those items that were included that exceeded $2 million.

**Q. WHAT WAS THE RESULT OF THIS REVISION?**

A. The Other Operations & Maintenance lag days increased from the 33.54 days incorporated in the Company's lead/lag analysis to 35.31 days. This is an increase in the other O&M lag days of 1.77 days.

**Q. BASED ON YOUR ADJUSTMENTS, WHAT IS YOUR RECOMMENDATION FOR OTHER OPERATIONS & MAINTENANCE LAG DAYS?**

A. I am recommending that the Company's proposed Other Operations & Maintenance lag days of 33.54 days be increased to 42.31 days. This incorporates the revised Other Operations & Maintenance lag day calculation resulting in 35.31 days plus the application of a seven day service lag, resulting in the 42.31 day recommendation.

**Q. DO YOU RECOMMEND THAT THIS BE A PERMANENT REVISION TO THE COMPANY'S 2010 LEAD/LAG STUDY?**

A. No, I am recommending the increase in the Other Operations & Maintenance lag days to 42.31 days be an interim measure for purposes of this general rate case filing. I recommend that the Commission direct the Company to provide a detailed lag study analysis on its Other Operations & Maintenance expense category, using 2010 data consistent with the other lead/lag study calculations, between now and the time of RMP's next Utah rate case filing. In conducting the revised analysis, the Commission should direct RMP to use 2010 invoices that are specific to items that are recorded in the expenses on its books to which the lag is being applied and not a blanket widespread analysis based on its full accounts payable reports. That analysis should not only look at the invoices, but should also take into consideration the service period for the services or costs that are being charged on the invoices. At the time of the next Utah general rate case filing, RMP should be required to provide the detailed workpapers showing how it derived the detailed Other O&M Expense lag days. In the interim, it is my opinion that increasing the other O&M expense lag to 42.31 days is a reasonable measure until a full and complete analysis based on detailed information and realistic assumptions can be conducted by the Company.

**Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED REVISIONS TO THE OTHER OPERATIONS & MAINTENANCE LAG DAYS ON THE OVERALL EXPENSE LAG DAYS?**

A. As shown on Exhibit OCS 3.5.D, page 3.5.1, the result is an increase in the overall expense lag days from the 35.84 days presented in the Company's analysis to 38.31 days.

**Q. WHAT IMPACT DO EACH OF YOUR RECOMMENDED MODIFICATIONS TO THE 2010 LEAD/LAG ANALYSIS HAVE ON THE NET REVENUE LAG DAYS CONTAINED IN THE COMPANY'S FILING?**

A. As shown on Exhibit OCS 3.5.D, page 3.5.1, the impact of my recommendations is that the net lag days calculated by RMP of 4.92 days be reduced to 1.45 days. The 1.45 days is the result of subtracting my recommended expense lag days of 38.31 days from my recommended revenue lag days of 39.76 days. Exhibit OCS 3.5.D shows that the impact of reducing the net revenue lag days to 1.45 days reduces the cash working capital requirement in Utah from $18,657,920 to $5,513,690, or a reduction of $13,144,230. This amount is based upon the Company's adjusted daily O&M expenses contained in the filing. The final impact of the reduction in the lag days would be automatically calculated in the Jurisdictional Allocation Model based on all of the adjustments to the Company's figures that are included in the model. In calculating the impact of the adjustment it is necessary to adjust the cash working capital input in the Jurisdictional Allocation Model, revising both the revenue lead days and expense lag days, resulting in the recommended net revenue lag of 1.45 days.

**<u>Accumulated Deferred Income Taxes</u>**

**Q. HAVE ANY EVENTS OCCURRED SINCE THE TIME THE COMPANY PREPARED ITS FILING THAT WOULD IMPACT THE ACCUMULATED DEFERRED INCOME TAX ("ADIT") OFFSET TO RATE BASE FOR THE FUTURE TEST YEAR ENDING MAY 31, 2013?**

A. Yes. *****BEGIN CONFIDENTIAL***** [redacted]

[redacted]

[redacted]

[redacted]

Redacted

[redacted]

[redacted] ***END CONFIDENTIAL***

**Q. DO YOU RECOMMEND THAT THE ABOVE IDENTIFIED ADJUSTMENT BE MADE IN THIS CASE?**

A. Yes. The adjustment to increase the ADIT offset to rate base is reflected on Confidential Exhibit OCS 3.19D.

**Q. ARE YOU AWARE OF ANY RECENT GUIDANCE FROM THE IRS THAT MAY IMPACT THE AMOUNT OF ADIT OFFSET TO RATE BASE INCLUDED IN THE TEST YEAR?**

A. Yes, in August 2011 IRS Revenue Procedure 2011-43 was issued. The revenue procedure provides a safe harbor method that taxpayers such as PacifiCorp may use to determine whether an expenditure to maintain, replace or improve electric transmission and distribution property must be capitalized. If the expenditure is not required to be capitalized, it can be expensed for tax purposes. The amount expensed for tax purposes may be referred to as the repairs deduction. The revenue procedure also provides procedures for obtaining automatic consent to change to the safe harbor method of accounting. It is my understanding that taxpayers that previously changed their tax accounting for repairs deductions associated with transmission and distribution assets can adopt the safe harbor method under Revenue Procedure 2011-43, which may result in an increase in the amount of repairs deduction for tax purposes.

PacifiCorp changed its method of tax accounting for repairs deductions effective with its 2008 federal income tax return. This change resulted in a significant increase in the ADIT offset to rate base and was addressed in a stipulation in Docket Nos. 09-035-03 and 09-035-23. As I recently became aware of Revenue Procedure 2011-43, I was unable to determine the impact on the test year ADIT offset to rate base that would result from application of the safe harbor method allowed for by the IRS and whether the impact has been incorporated in RMP's filing in this case. Data requests have recently been issued by the OCS to obtain the information needed to make this determination. It would be beneficial to the record in this case for RMP to address the safe harbor method of accounting allowed for in Revenue Procedure 2011-43 in its rebuttal filing, and to provide as part of the rebuttal filing the impact of the adoption on the ADIT offset to test year rate base if PacifiCorp either has adopted or plans to adopt the method.

**<u>Klamath Hydroelectric Settlement Agreement</u>**

**Q. ON EXHIBIT RMP__(SRM-3), PAGE 8.11, THE COMPANY INCLUDED SEVERAL ADJUSTMENTS ASSOCIATED WITH THE KLAMATH HYDROELECTRIC SETTLEMENT AGREEMENT. IS THE OCS PROPOSING ANY REVISIONS TO THE COMPANY'S ADJUSTMENT?**

A. Yes. The OCS recommends that the costs included in the adjusted test year by the Company associated with the Klamath relicensing and settlement process costs, the facilities removal costs, and the cost associated with the Klamath Hydroelectric Settlement Agreement ("KHSA") be removed and not passed on to ratepayers in the State of Utah. This recommendation is being presented and supported by the Director of the Office of Consumer Services, Michele Beck, as part of her testimony in this case. While Ms. Beck is presenting the OCS' position on this issue, I provide the quantification of the impact of her recommendation.

**Q. WHAT ADJUSTMENTS ARE NEEDED TO REFLECT THE IMPACT OF THE OCS' RECOMMENDATION THAT THE KLAMATH RE-LICENSING AND SETTLEMENT PROCESS COSTS, THE FACILIITES REMOVAL COSTS, AND THE KLAMATH HYDROELECTRIC SETTLEMENT AGREEMENT COSTS BE REMOVED?**

A. The necessary adjustments are reflected on Exhibit OCS 3.6D and impact rate base and operating expenses in this case. On Exhibit OCS 3.6D, the following adjustments are presented:

- The operation and maintenance costs resulting from the KHSA included in the Company's adjusted test year in this case of $3,787,888 on a total Company basis are removed.
- The facilities removal costs of $17,200,000 on a total Company basis are removed.
- The Company's proposed inclusion in rate base of $81,814,435 for the Klamath re-licensing and settlement process costs are removed.
- The Company's proposed annual amortization of the Klamath re-licensing and settlement process costs of $10,788,717 are removed.
- The Company's proposed acceleration of the depreciation resulting from the early retirement is being removed, resulting in a reduction to depreciation expense of $5,613,990 on a total Company basis and a $5,624,883 reduction to the depreciation reserve.

- Amounts added to plant in service since June 2010 as a result of the KHSA have been removed, reducing test year average plant in service by $3,957,918 and depreciation expense by $74,567 on a total Company basis.

**Q. WHY DID YOU REMOVE THE AMOUNTS ADDED TO PLANT IN SERVICE SINCE JUNE 2010 FOR THE KLAMATH FACILITY?**

A. Most, if not all, of the plant additions made to the Klamath facility since June 2010 would be the result of the KHSA implementation. As shown on Exhibit OCS 3.6D, Page 3.6.1, the Klamath plant balances are projected to increase by $3,957,918 from June 30, 2010 to the average test year level, going from $82,161,387 to $86,119,305. The $3,957,918 is removed on Exhibit OCS 3.6D.

In RMP's filing in Docket No. 10-035-124, Exhibit RMP__(SRM-3), at page 8.12.2, RMP projected $2,387,608 in plant additions related to the KHSA implementation from the end of the base year in that case – June 30, 2010 – to the end of the test year in that case. In the current case, at Exhibit RMP__(SRM-3), Page 8.11.2, the Company projects adding $2,195,444 between the end of the base year in this case – June 30, 2011 - and the end of the test year. Once projects that appear in both filings are removed, the projected amount of projects related to KHSA implementation between June 2010 and May 2013 is $4,307,658. Thus, the majority of, if not all of, the additions to the Klamath plant in service balances from June 2010 through the end of the test year in this case are associated with the KHSA implementation.

## <u>JURISDICTIONAL ALLOCATION FACTORS</u>

**Q. DO ANY OF OCS' RECOMMENDATIONS IMPACT THE JURISDICTIONAL ALLOCATION FACTORS?**

A. Yes. In determining the line loss factors in the GRID model, RMP used a simple five-year average of losses using 2006 through 2010 data. OCS witness Randall Falkenberg recommends in his direct testimony that the data be updated for a more recent five-year period using 2007 through 2011 data. Use of the updated five-year average reduces the system energy requirements presented by the Company. Mr. Falkenberg's recommended power cost adjustments incorporate the impact of this update. As use of the updated five-year average line losses reduces the system energy requirements, it also impacts the jurisdictional allocation factors that include system load in determining the allocation percentages between states.

**Q. WHAT IMPACT DOES CHANGING THE LINE LOSS HAVE ON TEST YEAR ENERGY REQUIREMENTS?**

A. Exhibit OCS 3.7D provides the impact on the energy requirements for Jurisdictional Allocation by using the more recent five-year average. Total system energy requirements decrease by 29,335 MWh, or 0.05%. The Utah energy requirements decrease by 47,412 MWh or 0.19%. Since the Utah energy requirements are declining at a greater percentage than the system as a whole when updated to a more recent five-year average line loss factor, the impact is a reduction in several of the jurisdictional allocation factors for the percentage allocated to the Utah jurisdiction.

Using the amounts presented in Exhibit OCS 3.7D, I incorporated the revised loads for jurisdictional allocation in the Jurisdictional Allocation Model in this case. Thus, the revenue requirements presented by the OCS that result in Exhibit OCS 3.1D include the impact of the updated loads.

**Q. WHAT IMPACT DID THE CHANGE IN LOADS HAVE ON THE PERCENTAGE ALLOCATIONS TO UTAH?**

A. Several allocation factors changed as a result of the change in loads. For example, the System Generation (SG) factor for Utah declined from 43.1547% in RMP's model to 43.1399% in the revised Jurisdictional Allocation Model. Similarly, the System Energy (SE) factor declined from 42.9534% to 42.8944%, and the System Overhead (SO) factor declined from 42.8536% to 42.8410%.

**Q. DID YOU NEED TO MAKE ANY FURTHER MODIFICATIONS TO THE AMOUNTS PRESENTED ON OCS 3.7D PRIOR TO INPUTTING THE ADJUSTMENT IN THE JURISDICTIONAL ALLOCATION MODEL?**

A. Yes. The information provided by the Company for energy sales and system load in response to OCS Data Request 5.2 included the Wyoming jurisdiction on a combined basis, whereas the Jurisdictional Allocation Model separates the Pacific Power and Rocky Mountain Power Wyoming jurisdictions in the model. Since the breakdown between each of the Wyoming jurisdictions was not provided, I allocated the resulting Wyoming load presented on Exhibit OCS 3.7D of 10,030,784 between the Pacific Power and the RMP jurisdiction on the ratio of load between those two jurisdictions contained in the Company's model.

## NET OPERATING INCOME

### Property Tax Expense Correction

**Q. SHOULD ANY REVISIONS BE MADE TO THE AMOUNT OF PROPERTY TAX EXPENSE INCLUDED IN THE TEST YEAR?**

A. Yes. In response to OCS Data Request 15.1, the Company acknowledged an error that was made in its calculation of the property tax expense for the test year ending May 2013. In calculating the adjustment to the base year level of property tax expense in Exhibit RMP__(SRM-3), page 7.2.1, RMP input an incorrect amount for the property tax expense for the base year ended June 2011. The adjustment was calculated using a base year level property tax expense of $100,512,228; whereas the response to OCS Data Request 15.1 shows that the corrected amount for the base year should have been $108,846,558. Consequently, the adjustment to increase property tax expense in the filing should have been $13,763,109 on a total Company basis and not the $22,097,439 adjustment incorporated in the Company's filing.

**Q. WHAT ADJUSTMENT NEEDS TO BE MADE TO REFLECT THE CORRECTION OF THIS ERROR?**

A. Property tax expense should be reduced by $8,334,330 on a total Company basis and $3,571,594 on a Utah jurisdictional basis. The calculation of this adjustment is presented on Exhibit OCS 3.8D.

**<u>Insurance Expense – Non-T&D</u>**

**Q. AS A RESULT OF THE DISCONTINUATION OF THE CAPTIVE INSURANCE WITH MEHC EFFECTIVE AT THE END OF MARCH 2011, THE COMPANY MADE SEVERAL ADJUSTMENTS TO BOTH ITS PROPERTY INSURANCE EXPENSE AND ITS O&M EXPENSE. ARE YOU RECOMMENDING ANY REVISIONS TO THE COMPANY'S ADJUSTMENTS ASSOCIATED WITH PROPERTY INSURANCE?**

A. Yes, I am recommending that the amount of expense associated with non-transmission and distribution ("Non-T&D") plant damage, which has been classified by RMP as either an accrual for self insurance expense or maintenance expense in the test year, be reduced.

**Q. HOW ARE THEY RECORDED?**

A. Both the amount accrued as a self insurance expense and the amount RMP identifies as a deductible amount falling under the category of maintenance expense is included in test year expenses. RMP has chosen an internal "deductible" of $1 million for non-T&D plant damages resulting in damages under the $1 million deductible on a per event basis being recorded in the maintenance expense accounts. RMP's prior rate case, Docket No. 10-035-124, was the first case in Utah in which the end of the MEHC Captive Insurance coverage was addressed in a Company proposed adjustment. As that case resulted in a stipulation, the issue was not specifically addressed in the Commission's decision.

**Q. COULD YOU PLEASE PROVIDE A TABLE SHOWING THE TOTAL NON-T&D DAMAGE COSTS NOT COVERED BY OUTSIDE INSURANCE THAT THE COMPANY IS PROPOSING TO IDENTIFY AS AN INSURANCE ACCRUAL?**

A. Yes. The table below provides a breakout, by year, of the amount the Company is identifying as self insurance expense to be recorded in Account 924 – Insurance Expense, as well as the three-year average amount it proposes to include in rates in Account 924. These amounts are in excess of the Company's selected deductible.

| | | Internal Insurance Portion |
|---|---|---|
| *"Deductible"* | *$* | *1,000,000* |
| | | |
| Apr 2008 - Mar 2009 | $ | 5,410,474 |
| Apr 2009 - Mar 2010 | $ | 847,444 |
| Apr 2010 - Mar 2011 | $ | 411,615 |
| Average | $ | 2,223,178 |

**Q. DO YOU KNOW THE AMOUNTS THAT WOULD BE CONSIDERED INTERNAL INSURANCE EXPENSE FOR T&D DAMAGES IN PRIOR PERIODS IF BASED ON PACIFICORP'S NEW APPROACH POST-MEHC CAPTIVE?**

A. Yes. According to the response to DPU 36.3, Attachment DPU 36.3, the amount would be $0 in each of the twelve month periods ended March 31, 2006, 2007 and 2008. In other words, no events caused damages exceeded the proposed $1 million deductible in the years 2006 through 2008.

**Q. COULD YOU EXPLAIN WHY THE TWELVE MONTH PERIOD ENDED MARCH 2009 IS SO MUCH HIGHER THAN THE OTHER TWO PERIODS PRESENTED IN YOUR TABLE AS WELL AS THE THREE PRIOR YEARS ENDING MARCH 31, 2006, 2007 AND 2008?**

A. Yes. Included in the total Non-T&D damages cost to the Company for the twelve months ended March 2009 is $6,410,474 associated with high runoff that caused flooding and a landslide that resulted in damage to the Swift hydro facility powerhouse. After the new assumed $1 million deductible, the entire remaining balance in the above table for the twelve months ended March 31, 2009 is for this one event. In fact, for the total six year period spanning April 2005 through March 2011, the entirety of the non-T&D damages that would fall under the new self-insurance portion (i.e., amounts after the $1 million per event deductible) are the result of this one event.

This event occurred between January 6th and January 8th, 2009 (hereafter referred to as January 8) and has a significant impact on the Company's proposed Non-T&D damages expense requested in this case. Costs for the following year, the twelve month period ended March 2010, included an additional $847,444 for the same event and costs for the period ended March 2011 included $411,615 for the event.

The entire balance of the Company's proposed Non-T&D self insurance expense in Account 924 of $2,223,178 is the result of this one event. In other words, during that three-year period in the Company's analysis, the entire balances that exceed its proposed $1 million internal "insurance deductible" threshold related to the January 8, 2009 high runoff event. Of the Non-T&D maintenance expense requested by the Company (i.e., the amount it is not proposing to be categorized as self insurance in Account 924), $333,333 is associated with the January 8, 2009 high runoff event calculated as the $1 million “deductible” divided by 3 for the 3 year average.

Thus, of the Company’s total forecasted Non-T&D damages expenses not covered by outside insurance, $2,556,511 is the result of the January 8, 2009 high runoff flooding and landslide event with the amounts split between Insurance Expense in Account 924 and Account 553 – Maintenance of Generation and Electric Plant Expense.

**Q. DO YOU HAVE ANY SPECIFIC INFORMATION REGARDING COSTS THAT WERE INCURRED BY THE COMPANY ASSOCIATED WITH THE HIGH RUN-OFF EVENT THAT OCCURRED ON JANUARY 8, 2009?**

A. Yes. RMP’s response to DPU 22.12 in Docket No. 10-035-124 provided a listing of costs by work order for the past three years for various repair costs, including those identified as Non-T&D expenses. Additionally, in response to DPU Data Request 36.3, Attachment DPU 36.3, the Company identified an additional $411,615 recorded for this event in the twelve months ended March 31, 2011. In OCS Exhibit 3.9D, page 3.9.2, I provide a listing of items identified by the Company as having to do with the January 2009 Swift River high runoff event.

Additionally, on September 2, 2009, Rocky Mountain Power provided notice to the Commission of two separate sole source contracts, one with JR Merit, Inc. and one with High-Tech Rock Fall Construction, Inc. The notice of sole source contracts with JR Merit, Inc. indicated that PacifiCorp entered into a sole source contract to provide emergency repairs at the Swift hydro facility powerhouse during January 2009. The notice indicated that the costs of the contract, which was estimated to be $1.45 million, had a final cost of $4,060,091.

The notice of sole source contracts with High-Tech Rock Fall Construction, Inc. indicated that the contract was also to provide emergency repairs at the Swift hydro facility powerhouse during January 2009. The notice indicated that the cost of the contract was estimated to be $750,000 and that the final costs were $1,096,542. Both of these notices of sole source contracts provide the following description of the event: “Beginning early on Tuesday, January 6, 2009 and continuing through January 8, 2009, very heavy rainfall in western Washington combined with warm air temperatures resulted in rapid snowmelt and high runoff causing flooding and a landslide resulting in damage to the Swift hydro facility powerhouse.”

**Q. SHOULD THE COST ASSOCIATED WITH THIS EVENT BE INCLUDED IN PROJECTING THE COST LEVEL TO INCORPORATE IN RATES FOR THE TEST PERIOD?**

A. No, the costs associated with this abnormal one-time event should be excluded in determining the amount to include in base rates on a going forward basis. Clearly, the January 8, 2009 high runoff event that caused the flooding and landslide, which resulted in damages to the Swift hydro facility powerhouse is a unique event that would not occur in a typical year. I recommend that this unusual one-time event be excluded in determining the average cost level to include in base rates.

**Q. WHAT IS THE IMPACT OF THE REMOVAL OF THIS EVENT ON THE COMPANY'S REQUEST?**

A. On Exhibit OCS 3.9D, page 3.9.1, I removed the impact of this January 8, 2009 runoff event for purposes of determining the three-year average cost level. Removing this event in projecting a normalized cost level results in a $2,333,178 reduction to the Company's proposed internal self insurance expense and a $333,333 reduction to the Company's proposed Non-T&D maintenance expense associated with potential future damages. In other words, projected test year expenses in RMP's filing should be reduced by $2,556,511.

**<u>Generation Overhaul Expense</u>**

**Q. PLEASE DISCUSS RMP'S ADJUSTMENT TO NORMALIZE GENERATION OVERHAUL EXPENSE.**

A. In its filing, RMP adjusted the base year generation overhaul expense to reflect a four-year average cost level. In deriving its adjustment, RMP used actual overhaul costs for the past four years, which it escalated to base year levels, on a plant by plant basis for the plants that were owned for the entire four-year period. RMP then added a combination of escalated actual and projected annual costs to derive a four-year average overhaul cost for new plants that were not in service over the entire four-year historic period. The new plants included Lake Side and Chehalis. RMP's adjustment resulted in a $2,600,573 ($1,122,253 Utah) reduction to the base year overhaul expense level.

The inclusion of overhaul costs in rates at an average, normalized level is consistent with past Commission decisions and recognizes that the costs can fluctuate significantly from year to year. However, the method used by RMP in this case, which uses historic amounts that have been escalated to the base year, deviates from the method approved by the Commission in prior cases.

**Q. HOW DOES RMP'S METHODOLOGY DEVIATE FROM THE METHOD APPROVED BY THE COMMISSION IN PRIOR CASES?**

A. In the Orders in Docket No. 07-035-93, issued August 11, 2008, and Docket No. 09-035-23, issued February 18, 2010, the Commission included overhaul costs in rates based on a four-year average historic cost level for existing plants, excluding escalation, and a combination of actual and projected four-year average cost level for new generation plants. In each of those prior dockets, the Commission disallowed the escalation of the historic costs in determining the normalized cost level for inclusion in rates. In the last rate case, Docket No. 10-035-124, parties reached a settlement that did not specifically address the method for normalizing generation overhaul costs in rates. Therefore, the normalizing treatment was not identified in the Commission's Order in that case. It is worth noting that RMP did not escalate the historic costs in its filing in that case, but instead followed the Commission approved methodology. However, the Division did recommend that the historic costs be escalated prior to determining the average, normalized balance of overhaul costs to include in rates in its prefiled direct testimony.

**Q. HOW WAS THE ISSUE OF THE ESCALATION OF HISTORICAL GENERATION OVERHAUL COSTS FOR PURPOSES OF DETERMINING THE NORMALIZED COST LEVEL ADDRESSED BY THE COMMISSION IN DOCKET NO. 07-035-93?**

A. The Commission addressed this issue in the August 11, 2008 Order in Docket No. 07-035-93, at pages 81 – 82, as follows:

Redacted

> First, in our recollection, this is the first time escalation within averaging has been proposed. We are not persuaded this is an appropriate approach and are concerned, if accepted here, such a practice would be extended to other cost items, by both PacifiCorp and Questar Gas Company. The basis for using averages of actual costs is because book amounts vary from year to year, and the costs in one year are not considered normal. In the next case, following the precedent established here, the Company will assert this year's actual expense, considered in this case to be abnormal, can be escalated to obtain a reasonable level of expense for the next year. This seems to defeat the purpose of constructing an average, which is to smooth out the year-to-year abnormalities. Escalation in the Company's approach serves merely to inflate the average, and the average is already higher than the budget.

**Q. HOW DID THE COMMISSION ADDRESS THIS ISSUE IN DOCKET NO. 09-035-23?**

A. In Docket No. 09-035-23, RMP again requested that the historical balances used in deriving the four-year average normalized cost be escalated, while OCS again recommended that the historical amounts not be escalated. In its direct testimony in that Docket, the DPU did not apply escalation to the historical balances in deriving its recommended normalized amount. However, in the surrebuttal testimony filed by DPU witness Artie Powell, the DPU modified its position in that it recommended that the amounts be escalated. The Commission's February 18, 2010 Order in Docket No. 09-035-23, at page 96, describes the DPU's position: "According to the Division, the Commission could choose to leave the issue open for more discussion, if needed, in future cases without making any broad policy decisions here, but it recommends the adjustment adopted in the 2007 rate case not be made in this case."

At page 97 of its February 18, 2010 Order, the Commission resolved the issue of whether or not the historical amounts should be escalated in determining the normalized amount to include in rates as follows:

> In addition to those reasons enunciated in our prior order in Docket No. 07-035-93, the Company provides no analysis of how their approach when applied to historical data provides reasonable results over time. The evidence provided in this case, and in other recent cases, is not sufficient to support adoption of the Company's method. For these reasons we do not accept the Company's recommendation, rather we uphold our original decision in Docket No. 07-035-23 and therefore accept the Office's adjustment.

The Order did not indicate that the issue was being held "open for more discussion, if needed, in future cases" as suggested by the Division in that docket. Rather, it specifically found that the evidence provided in the case, as well as in other then recent cases, was not sufficient to support the escalation of the historical balances in deriving the normalized level to include in rates.

**Q. HAS RMP PRESENTED ANY NEW EVIDENCE IN THIS CASE IN SUPPORT OF ESCALATION OF THE HISTORICAL BALANCES IN DERIVING THE NORMALIZED GENERATION OVERHAUL EXPENSE LEVEL THAT HAS NOT PREVIOUSLY BEEN CONSIDERED BY THE COMMISSION OR THAT YOU FIND PERSUASIVE OR COMPELLING?**

A. No. There was nothing new presented by the Company with regards to this issue that was not previously presented to or considered by the

Commission in Docket No. 09-035-23. While RMP witness Steven McDougal contends that the historic values should be escalated for inflation, he is silent with regards to productivity that would occur over time that would mitigate or offset the pressures of generation inflationary factors. There is nothing new presented in this case that should lead to the conclusion that the historical costs should be escalated in determining the normalized cost level. The Commission should re-affirm, once again in this docket, that the historical generation overhaul expenses should not be escalated for purposes of normalizing generation overhaul expense to include in base rates.

**Q. WHAT IS THE OCS' RECOMMENDATION WITH REGARDS TO WHETHER OR NOT THE HISTORICAL COST LEVELS SHOULD BE ESCALATED IN DERIVING THE AVERAGE?**

A. The issue of whether or not the historical costs should be escalated in deriving the normalized amount for inclusion in rates was thoroughly vetted by the parties in RMP Docket Nos. 07-035-93 and 09-035-23. The issue was addressed in testimony in both of those cases, and I was cross examined on this very issue during the hearings in those cases before the Commission. In each of those cases, the Commission determined that the historical costs should not be escalated in deriving the normalized cost level to include in rates. RMP's repeated recommendation that the costs be escalated in deriving the normalized generation overhaul expense level should, yet again, be denied.

As shown on Exhibit OCS 3.10D, test year expenses should be reduced by $929,786 ($401,249 Utah) to remove the impact of the Company's proposed escalation of the historic costs prior to normalization.

**<u>Incremental Generation O&M (Non-Overhaul)</u>**

**Q. WOULD YOU PLEASE BRIEFLY DESCRIBE THE COMPANY'S ADJUSTMENT FOR INCREMENTAL GENERATION OPERATION AND MAINTENANCE EXPENSE?**

A. In this case, RMP has taken a different approach in adjusting its generation plant operation and maintenance expenses as compared to the approach it has taken in prior proceedings. In the past several cases, RMP has proposed specific adjustments to its base year generation and transmission O&M expenses associated with either the addition of new facilities, substantive changes made to specific facilities, or known contract changes. For example, in the prior rate case, Docket No. 10-035-124, RMP made an adjustment to incremental generation and transmission O&M as the result of placing three wind facilities and three new transmission resources in service, as well as the cost impacts of new pollution control projects that were being placed into service prior to the end of the test year in that case. In that case, the Company also proposed adjustments associated with some contract changes associated with managing the gas turbine parts and services contract for the Lake Side plant; switching to a higher SO2 content coal at Cholla 4; and plans to retire the Little Mountain plant during the future test year. These adjustments were based on specific identifiable changes.

While a similar approach that identifies projected cost changes is being used for the hydro and wind generation facilities in this case, RMP is using a new approach in which it is adjusting the O&M costs (excluding labor, net power costs and overhauls) to the budgeted test year level on a plant by plant basis for the thermal generation plants. The non-labor, non-overhaul, and non-power cost O&M expenses for all of the coal fired generation, gas and geothermal generation and partner operated generation plants are included in the adjusted test year based on budgeted amounts. Exhibit RMP__(SRM-3), page 4.9.1, shows that when compared to the escalated base year cost level, the adjustment results in a $1,681,495 reduction to the Company owned coal fired generation O&M expense, a $2,333,911 reduction to the Company owned gas & geothermal generation O&M expense and a $4.95 million increase in the partner operated generation plant O&M expense. Thus, PacifiCorp anticipates that the increases above the base year level of operating and maintaining its owned thermal generation plants (excluding the labor, net power and overhaul costs) will be less than the results of simply applying its proposed escalation factors to the base year costs. However, the budgets presented by the partner operated thermal generation plants are projected to increase by more than the inflation level. The net result, which is shown on Exhibit RMP__(SRM-3), page 4.9.1, is that the O&M expenses (excluding labor, net power costs and overhauls) for thermal generation plants are projected to increase $10,143,199 above the base year level of $174,036,384, exceeding the inflation adjustment by $935,256.

**Q. DO YOU RECOMMEND ANY ADJUSTMENTS TO THE PROJECTED INCREMENTAL GENERATION O&M EXPENSE?**

A. Yes. I recommend three adjustments be made to RMP's projected incremental generation O&M expenses. Specifically, I recommend that: (1) the hydro generation O&M expense be reduced by $535,209 ($230,967 Utah) to reflect the impact of updated information received from FERC regarding Land Use Fees; (2) the expense included for oil changes at the wind generation facilities be reduced by $2,029,333 ($875,759 Utah); and (3) the amount included for materials expenses at the wind generation facilities be reduced by $568,024 ($245,131 Utah). I will discuss each of these four adjustments below.

**Q. PLEASE DISCUSS YOUR ADJUSTMENT TO REDUCE THE HYDRO GENERATION O&M EXPENSE.**

A. At the time RMP's testimony was prepared, there was uncertainty regarding the level of FERC land use fees that the Company would incur in the test year related to the hydro licenses it holds. According to the direct testimony of Mark Tallman, at pages 7 – 8, in projecting test year FERC land use fee expenses, the Company "…used the invoice amount proposed by FERC in its 2009 revised fee schedule which was vacated in early 2011 due to a successful appeal by PacifiCorp and other licensees." The result was RMP's inclusion of $717,319 in the test year for the FERC land use fee.[3]

PacifiCorp received the FERC land use fee invoices in March, with payment due in April 2012. According to the invoice, the annual fee is $182,115[4], which is significantly lower than the $717,319 incorporated in the filing for the test year. As shown on Exhibit OCS 3.11D, test year expenses should be reduced by $535,204 ($230,967 Utah).

**Q. PLEASE DISCUSS THE AMOUNT INCLUDED IN RMP'S FILING FOR OIL CHANGES AT ITS WIND FACILITIES.**

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[3] Exhibit RMP__(SRM-3), page 4.9.2.
[4] Response to OCS Data Request 8.16

A. RMP increased base year expenses by $3,044,000 to reflect the cost of oil changes on its wind generation turbines at nine of the 13 wind projects owned by the Company. The cost was estimated assuming 381 wind turbines having oil changes during the test year at an estimated cost of $8,000 per wind turbine.[5]

**Q. IS THE OIL CHANGED ON THE WIND TURBINES ON AN ANNUAL BASIS?**

A. No. The projected oil changes in the test year will be the first oil changes for the 381 wind turbines. In fact, in response to OCS Data Request 8.14, the Company indicated that the average manufacturer recommended time span between oil changes on the Company owned wind turbines is three years. If RMP waits until the test year to change the oil on all 381 turbines, many will exceed the recommended oil change span. The 381 turbines for which the oil change costs are incorporated in the test year ended May 31, 2013 were placed into service in the years 2007 through 2010. Thus, the Company projects replacing oil in wind turbines during the test year that were placed into service over a four year period.

**Q. SHOULD THE AMOUNT INCLUDED IN THE FORECAST TEST YEAR FOR OIL CHANGES BE REDUCED?**

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[5] Response to OCS Data Request 8.14.

A. Yes. Since the manufacturer has recommended the oil changes occur every three years, and the Company's adjustment assumes that oil will be changed on wind turbines that were placed into service over a four year period, the amount of cost in the test year is overstated and not reflective of a normal cost level. I recommend that 2/3rds of the costs be removed. As shown on Exhibit OCS 3.12D, test year expenses should be reduced by $2,029,333 ($875,759 Utah). This would allow 1/3rd of the costs as the oil changes would occur once every three years under the manufacturer recommendations.

**Q. WHAT AMOUNT IS INCLUDED IN THE ADJUSTED TEST YEAR FOR MATERIALS EXPENSE AT THE WIND FACILITIES?**

A. RMP has projected expenses in the test year associated with replacement parts and materials on the wind facilities of $6,389,472, which is an increase to the base year cost of $4,811,093. While RMP is projecting a $4.8 million increase to this cost, it is also projecting a $3.4 million reduction in third-party contract costs at the wind facilities. According to the direct testimony of Mark Tallman, at page 4, warranties will expire at ten of the 13 wind projects owned by the Company either before or during the test period. The Leaning Juniper I and Goodnoe Hills warranties expired prior to the base period and the Dunlap I and Marengo wind projects have warranties that expire during the test year. Foot Creek I will be the only wind project that will have a warranty agreement in place after the test year. Thus, costs that were previously covered under the warranties and third-party agreements will now be covered under operating expenses.

**Q. HOW DID RMP ESTIMATE THE AMOUNT OF REPLACEMENT PARTS AND MATERIALS EXPENSE AT THE WIND FACILITIES FOR THE TEST YEAR?**

A. Mr. Tallman, at page 4 of his testimony, indicates that the Company used historical parts and materials costs to arrive at an estimated cost on a per-turbine basis. The resulting cost per turbine was then applied to the projects with turbines out of warranty during the test year.

**Q. COULD YOU PLEASE ELABORATE ON HOW THE COST ON A PER TURBINE BASIS WAS DERIVED BY THE COMPANY?**

A. Based on the confidential response to OCS Data Request 8.15b, Confidential Attachment OCS 8.15b, *****BEGIN CONFIDENTIAL***** [redacted]

[redacted]

[redacted] *****END CONFIDENTIAL*****

**Q. WHAT IS THE RESULT OF YOUR RECOMMENDED REDUCTION TO THE TEST YEAR WIND MATERIALS EXPENSE?**

A. As shown on Exhibit OCS 3.13D, I recommend the test year costs be reduced by 8.89%, which results in a $568,024 ($245,131 Utah) reduction to expense.

**<u>Post-Retirement Benefits – FAS 106 Expense</u>**

**Q. HAS THE COMPANY MADE ANY SIGNIFICANT CHANGES TO ITS EMPLOYEE BENEFIT PLAN OFFERINGS SINCE THE TIME OF THE LAST RATE CASE?**

A. Yes. PacifiCorp has implemented a significant benefit design change to its post-retirement welfare plan. This change is discussed at page 14 of the direct testimony of Erich Wilson. The change, which was effective January 1, 2012, results in the Company now providing an annual contribution to the health reimbursement account for its retired employees as opposed to a monthly subsidy structured plan. This has resulted in significant cost savings with regards to the provision of retirement medical plan costs. Mr. Wilson's testimony indicates that this change in the benefit design reduces post-retirement welfare plan costs by $13.1 million in the test year. Company Exhibit RMP__(SRM-3), at page 4.2.7 shows the amount of post-retirement benefits-FAS 106 expense going from $15,216,196 on a net of joint venture basis in the base year ended June 2011 to $2,141,507 in the forecast test year ended May 2013, a reduction of $13,074,690.

**Q. ARE YOU RECOMMENDING ANY FURTHER ADJUSTMENTS TO THE AMOUNT OF POST-RETIREMENT BENEFITS-FAS 106 EXPENSE INCLUDED IN THE ADJUSTED TEST YEAR IN THIS CASE?**

A. Yes. An additional reduction to the amount included in the test year needs to be made. According to Filing Requirement R746-700-20.C.3.e, the amount of post-retirement benefits—FAS 106 expense incorporated in the test year ending May 31, 2013 was based on projected expense of $1.5 million for the 2012 retirement plan year and $3.2 million for the 2013 plan year. Each of these amounts was prorated for the number of months in the test year to derive the projected test year expense on a gross basis of $2,208,333. After application of the percentage of those costs that go to joint ventures, the amount included in the test year was $2,141,507. OCS Data Request 6.12 asked the Company to provide an update to its test year PBOP expense that would result from the impact of reflecting actual 2011 plan experience as well as use of the actual assumptions that were selected at the end of 2011 for the 2012 plan year. According to the Company's response, the revised 2012 PBOP expense is $400,000 on a gross basis. Using the factor incorporated in the Company's filing to determine the net of joint venture amount of 96.974%, the revised 2012 PBOP expense would be $387,996 for the 2012 plan year which would include seven months of the test year in this case. This is significantly lower than the amount assumed in the Company's filing for 2012 of $1.5 million prior to allocation to the joint ventures.

**Q. DID THE COMPANY PROVIDE REVISED ESTIMATES FOR ITS 2013 PBOP EXPENSE?**

A. No. OCS Data Request 6.12 asked the Company to provide updated information for both 2012 and 2013. While the Company provided the revised 2012 PBOP expense of $400,000 (before netting out joint ventures), it indicated that "The Company has not performed an analysis of these impacts on 2013 PBOP expense." Consequently, the Company has not provided an updated 2013 expense projection.

**Q. WHAT ADJUSTMENT DO YOU RECOMMEND?**

A. I recommend that the amount of PBOP expense incorporated in the test year in the Company's filing be revised to reflect the updated 2012 PBOP expense that was provided by the Company in response to OCS Data Request 6.12. As the Company did not provide the requested update for the revised 2013 expense and has not justified a cost increase above the revised 2012 expense amount I recommend that this amount be used for estimating the test year expense level.

**Q. WHAT ADJUSTMENT IS NECESSARY TO REFLECT YOUR RECOMMENDATION?**

A. As shown on Exhibit OCS 3.14D, test year expenses should be reduced by $1,240,541 on a total Company basis and $531,263 on a Utah basis.

**Q. ARE THERE ANY OTHER FACTORS BEYOND THE SIGNIFICANT PLAN CHANGES THAT ALSO CAUSED THE SIGNIFICANT REDUCTION TO THE PBOP EXPENSE IN THE TEST YEAR?**

A. Yes. Since the time of the last rate case the transition obligation associated with the initial implementation of accounting for post-retirement benefit on an accrual basis has been fully amortized. This assisted in greatly reducing the amount of expense going-forward associated with the post-retirement medical benefit cost.

**<u>Cost Savings Not in Test Year</u>**

**Q. HAS THE COMPANY IDENTIFIED ANY COST SAVING MEASURES OR COST CONTAINMENT ACTIVITIES THAT IT HAS UNDERGONE?**

A. Yes. Company witness Richard Walje discusses several cost containment measures undertaken by the Company on pages 9 and 10 of his direct testimony. The majority of the cost containment measures identified by Mr. Walje were implemented either during or subsequent to the base year in this case.

**Q. SINCE THE COST SAVING MEASURES WERE IMPLEMENTED EITHER DURING OR AFTER THE BASE YEAR USED BY THE**

**COMPANY IN PREPARING ITS FILING, HAVE THE COST SAVINGS BEEN INCLUDED IN THE FORECAST TEST YEAR ENDING MAY 31, 2013?**

A. No, they have not. Adjustments should be made to the adjusted test year expenses to reflect the impact of the cost saving or cost containment measures that have been implemented by the Company.

**Q. WHAT ADJUSTMENT SHOULD BE MADE TO REFLECT THE IMPACT OF THE COST CONTAINMENT MEASURES ON THE TEST YEAR EXPENSES?**

A. I am recommending that five separate adjustments be made to reflect the impact on test year expenses contained in the filing associated with the cost containment measures that have been implemented by the Company either during or subsequent to the base year used in this case. Each of the recommended adjustments is provided in Exhibit OCS 3.15D and result in total recommended cost saving adjustments of $1,222,850 on a total Company basis and $777,104 on a Utah basis. Each of the recommended adjustments on a total Company and a Utah basis is presented in the table below:

| Cost Savings Measure: | Total Amount | Utah Amount |
|---|---|---|
| In-House Electronic Customer Payment Processing | $ (729,461) | $ (363,950) |
| Customers Switching to Electronic Billing | (342,077) | (342,077) |
| Reduction in Community Organization Memberships | (32,306) | (13,845) |
| Elimination of Individual Safety Recognition Program | (106,506) | (51,221) |
| Seminar Travel Savings | (12,500) | (6,012) |
| | $ (1,222,850) | $ (777,104) |

**Q. WOULD YOU PLEASE GO OVER EACH OF THE COST SAVING MEASURES IDENTIFIED IN THE ABOVE TABLE?**

A. Yes. The first cost saving measure is associated with the Company processing customer electronic payments in-house beginning in January 2011. Based on the Company's response to OCS Data Request 8.1, the total cost included in the base year for the vendor that provided the outsourced services, which are now done in-house, was $701,374 in the base year. Using the 4.86% escalation factor for Account 903 contained in the Company's filing results in adjusted costs incorporated in the test year of $735,461 for the vendor services that will no longer be utilized. The response also indicates that the Company will pay a fee of $6,000 in both 2012 and 2013 for its customer service agents to access the vendor's agent portal for historical payment transaction data. Thus, the net cost savings that will be realized in the test year associated with in-sourcing this function is $729,461 ($363,950 Utah). The Company indicated in its response to OCS Data Request 8.1(a) that it will reflect an adjustment for these savings in its rebuttal testimony.

The second adjustment presented on the table is to reflect the cost savings that will result from customers in Utah switching to electronic billing instead of receiving paper copies of bills through the mail In calculating the adjustment on Exhibit OCS 3.15D, page 3.15.1, I applied the savings per statement identified by the Company of $0.47 to the increase in the number of paperless bills that would be distributed in the test year as compared to those that were distributed in the base year in this case. This adjustment is based on information provided by the Company in response to OCS Data Request 8.2 and results in projected test year savings on a Utah basis of $342,077.

**Q. WOULD YOU PLEASE DISCUSS THE NEXT COST SAVING MEASURE IDENTIFIED IN YOUR TABLE FOR A REDUCTION IN COMMUNITY ORGANIZATION MEMBERSHIPS?**

A. Yes. At page 10 of his testimony, Mr. Walje indicates that the Company has reduced its membership in community organizations. In response to OCS Data Request 8.3, the Company indicated that the reduction in memberships began in January 2012 and identified the planned reductions in memberships for the test year. The Company identified total anticipated cost savings from these reductions of $31,018 that were incurred in the base year. After application of the escalation factor used in the case, the cost reduction in the test year is $32,306 on a total Company basis and $13,845 on a Utah basis.

**Q. PLEASE DISCUSS THE TWO REMAINING COST SAVING ADJUSTMENTS IDENTIFIED ON YOUR TABLE.**

A. At page 10 of his testimony, Mr. Walje indicated that the Company had eliminated employee safety recognition gifts for transmission and distribution employees. Based on the response to OCS Data Request 14.2, the amount of expense included in the adjusted test year for the individual safety recognition program that has been eliminated is $106,506 ($51,221 Utah). These costs that will no longer be incurred should be removed from the test year.

The final item being adjusted on Exhibit OCS 3.15D is the result of the Company converting the annual estimator seminar to an on-line forum thereby eliminating various travel costs, which is discussed on page 10 of Mr. Walje's direct testimony. According to the response to OCS Data Request 8.5, the total projected travel related savings is approximately $50,000, 25% which is allocated to operation and maintenance expenses with the remaining costs going to capital. Thus, the projected O&M expense savings in the test year are $12,500 ($50,000 x 25%) on a total Company basis and $6,012 on a Utah jurisdictional basis.

As shown on Exhibit OCS 3.15.D, these five separate cost saving adjustments result in total projected cost savings of $1,222,850 in the test year ($777,104 Utah).

**Oregon Rate Dispute Costs (Wah Chang Matter)**

**Q. ARE YOU RECOMMENDING ANY ADJUSTMENT TO REMOVE THE COST ASSOCIATED WITH LEGAL PROCEEDINGS THAT OCCURRED IN THE BASE YEAR IN THIS CASE?**

A. Yes. During the base year ended June 2011, the Company participated in a jury trial in Oregon that was specific to billing disputes involving an Oregon industrial customer. The costs associated with this matter were not removed from the base period, thus they were escalated into the test year in this case. I recommend that all of the costs included in the adjusted test year associated with this matter be removed.

**Q. COULD YOU PLEASE PROVIDE SOME BACKGROUND REGARDING THE OREGON BILLING DISPUTE?**

A. Yes. The Company's 10-K for the year ended December 31, 2011, at page 28, discusses various legal proceedings. Included in that discussion is the description of several disputes with Wah Chang, which is a large industrial customer receiving service from PacifiCorp in the State of Oregon. Two different disputes are specifically discussed regarding Wah

Chang and PacifiCorp. The 10-K, at page 28, specifically addresses the dispute with Wah Chang as follows:

> In December 2000, Wah Chang, a large industrial customer of PacifiCorp filed an action before the OPUC asserting that the rates set by a special tariff with PacifiCorp and approved by the OPUC were not just and reasonable due to alleged market manipulation during the energy crisis. In October 2001, the OPUC dismissed Wah Chang's petition and found that Wah Chang assumed the risk of price increases under the special tariff. Wah Chang petitioned the Circuit Court for Marion County, Oregon for review of the OPUC's order. In June 2002, the Circuit Court for Marion County, Oregon granted Wah Chang's motion for review and ordered the OPUC to reopen the record to allow Wah Chang the opportunity to present new evidence. In September 2009, the OPUC dismissed Wah Chang's petition and reaffirmed that the rates set by the special tariff were just and reasonable. In October 2009, Wah Chang filed with the Oregon Court of Appeals a petition for judicial review of the OPUC's September 2009 order denying Wah Chang relief. In July 2010, the Oregon Court of Appeals accepted judicial review.
>
> In a separate but related proceeding, in December 2000, Wah Chang filed a complaint in the Circuit Court for Linn County, Oregon asserting that the OPUC-approved special tariff with PacifiCorp is subject to rescission based on theories of mutual mistake of fact, frustration of purpose and impracticability. In April 2011, Wah Chang's claims were presented during a jury trial, and all claims, including the claim for punitive damages, were resolved in PacifiCorp's favor. Wah Chang did not appeal this outcome and the outcome had no impact on PacifiCorp's consolidated financial results.

**Q. WHY DO YOU RECOMMEND THAT THESE COSTS BE REMOVED FROM THE TEST YEAR IN THIS CASE?**

A. These costs should be removed for several reasons. First, and foremost, the costs involve a dispute with a large industrial customer in Oregon. Any revenues received from that large industrial customer would be

Oregon jurisdictional revenues and not passed onto customers in Utah. Thus, any costs incurred by the Company in defending its charges to the Oregon industrial customer should be assigned situs to Oregon and not allocated to Utah. When asked why these costs were allocated to Utah in OCS Data Request 8.8, the Company indicated that “Legal expenses are generally allocated system-wide unless identified with a state jurisdictional rate proceeding or state specific issue.” Disputes with Wah Chang, which is a large industrial customer in Oregon and pertain specifically to the rates charged in the State of Oregon, is a state specific issue that should have been assigned directly to Oregon.

The second reason these costs should be removed from the test year is that they are non-recurring in nature. According to the 10-K language quoted above, these matters have been largely resolved, thus the costs should not be incurred in the test year in this case.

**Q. WHAT ADJUSTMENT IS NECESSARY TO REMOVE THE COST ASSOCIATED WITH THE WAH CHANG MATTER FROM THE TEST YEAR IN THIS CASE?**

A. The Company provided an itemization of all costs recorded in the base year and escalated into the test year associated with the Wah Chang matter in its confidential Attachment OCS 8.8. The amounts were provided both on a total Company and on a Utah jurisdictional basis. In order to remove these costs from the test year, ****BEGIN CONFIDENTIAL**** [redacted] ****END CONFIDENTIAL**** This adjustment is shown on Confidential Exhibit OCS 3.16D.

**<u>CWIP Write-Offs</u>**

**Q. DID THE COMPANY REMOVE ANY EXPENSES ASSOCIATED WITH THE WRITE-OFF OF PROJECTS THAT WERE PREVIOUSLY RECORDED IN CONSTRUCTION WORK IN PROGRESS ("CWIP") IN ITS FILING?**

A. Yes. In Exhibit RMP__(SRM-3), at page 4.4, RMP removed $3,033,000 from base year expenses associated with its write-off of costs incurred for the Jim Bridger turbine upgrades. The reason the costs were removed was described by Company as follows:

> The contract with the vendor is being renegotiated due to certain portions of the Jim Bridger turbine upgrade projects being delayed, deferred and/or potentially cancelled due to project reconfiguration, scope and timing changes in the projects which result from transmission constraints and other issues. This should not impact results of operations.

**Q. ARE THERE ADDITIONAL CAPITAL PROJECTS THAT WERE WRITTEN OFF TO EXPENSE IN THE BASE YEAR THAT SHOULD ALSO BE REMOVED?**

A. Yes, several additional write-offs should be removed from expense. These include the write-off of a capital project to replace the switchgear at the Huntington Units 1 and 2 that was cancelled and the write-off of electronic security projects at the generation plants that were being done to comply with NERC/Critical Infrastructure Protection Standards that were cancelled.

**Q. WHY WAS THE SWITCHGEAR PROJECT AT HUNTINGTON UNITS 1 AND 2 CANCELLED?**

A. While preparing for installation of the replacement switchgear, concerns were raised by management about risks required to install the equipment. The Company decided to cancel the project after additional engineering reviews were conducted.[6] The Company charged $735,117 to expense in the base year for this project, which would result in $788,266 in the test year after application of the escalation factor incorporated in RMP's filing. The costs for this cancelled project should be removed from test year expenses and not passed on to ratepayers.

**Q. PLEASE DISCUSS THE NERC/CRITICAL INFRASTRUCTURE PROTECTION STANDARDS SECURITY PROJECTS THAT WERE WRITTEN-OFF DURING THE BASE YEAR.**

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[6] Response to OCS Data Request 17.6.

A. During the base year, the Company charged $1,842,475 to expense for the write-off of electronic security projects that were cancelled at various generating plants. The costs were escalated resulting in $1,975,686 included in test year expenses associated with the write-offs. The costs written-off on a per plant basis is provided in Exhibit OCS 3.17D, page 3.17.1. The costs for the electronic security project that was cancelled were incurred by the Company in 2009 and 2010 and consist of contractor costs for installing and configuring software.[7] In February 2010, PacifiCorp Energy management and the PacifiCorp information technology department performed an internal reassessment of the project and determined the project, for which over $1.8M of costs had already been incurred, should be replaced with a different project supported by internal resources instead of an outside vendor. The replacement project is now being done in-house by the Company.[8] Given the fact that the determination to cancel the project was made in February 2010, which is several months before the start of the base year, it is not clear why the write-off of the project to expense occurred during the base year ended June 30, 2011. The costs associated with the cancelled project should be removed from test year expenses and not passed on to RMP's ratepayers.

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[7] Response to OCS Data Request 6.2

[8] Response to OCS Data Request 17.6

Redacted

**Q. WHAT ADJUSTMENT IS NEEDED TO REMOVE THE COSTS ASSOCIATED WITH THE WRITE-OFFS FROM THE TEST YEAR.**

A. As shown on Exhibit OCS 3.17D, test year expenses should be reduced by $2,763,952 on a total Company basis and $1,192,783 on a Utah jurisdictional basis.

**Q. DO YOUR RECOMMENDED ADJUSTMENTS, COUPLED WITH THE ADJUSTMENT MADE BY RMP TO REMOVE THE WRITE-OFF ASSOCIATED WITH THE CANCELLED JIM BRIDGER TURBINE UPGRADE, RESULT IN ALL OF THE BASE YEAR CWIP WRITE-OFFS BEING REMOVED?**

A. No. Base Year CWIP write-offs totaled $8,020,913.[9] After the adjustments recommended above and RMP's adjustments are made, the remaining amount in the Base Year ended June 30, 2011 is $2,410,321.

**<u>Deseret Power Dispute</u>**

**Q. RMP'S FILING INCLUDES AN ADJUSTMENT TO NORMALIZE THE UNCOLLECTIBLE EXPENSE SPECIFIC TO UTAH. WERE ADDITIONAL COSTS RECORDED IN UNCOLLECTIBLE EXPENSE DURING THE BASE YEAR THAT SHOULD BE EXCLUDED FROM THE TEST YEAR?**

[9] Filing Requirement R746-700-22-D.2(d).

A. Yes. Base year Uncollectible Accounts expense recorded in Account 904 include $390,827 that is not state specific and instead allocated using the CN allocation factor. The $390,827 was escalated resulting in $409,839 in the test year. The base year expense of $390,827 includes $375,620 associated with the write-off of interest that had been accrued by the Company on amounts Deseret Power Electric Cooperative (“DPEC”) had refused to pay associated with its percentage share of the scrubber and turbine upgrade projects at the Hunter Unit 2 generation facility. As a result of an arbitration ruling that was unfavorable to PacifiCorp, the accrued interest on the outstanding costs was written-off on PacifiCorp’s books to Account 904 – Uncollectible Accounts. In response to OCS Data Request 14.3, the Company indicated that it will remove the costs when it files its rebuttal testimony. As shown on Exhibit OCS 3.18D, the escalated test year expenses should be reduced by $393,875 ($169,977 Utah) to remove these costs.

**Q. ARE ADDITIONAL COSTS INCLUDED IN THE TEST YEAR ASSOCIATED WITH THE DPEC DISPUTE?**

A. Yes. DPEC is a joint owner with PacifiCorp and another entity in Hunter Unit 2. A federal lawsuit was filed by DPEC against PacifiCorp in which DPEC contends that certain capital additions at the Hunter Unit 2 generation facility were not consistent with “Reasonable Utility Practice” as the term is defined by the Ownership and Maintenance Agreement and is refusing to fund its portion of the projects. During 2011, two separate arbitrations occurred resulting in unfavorable rulings for PacifiCorp with regards to the scrubber upgrade project and the turbine upgrade project at the plant. Additional issues in the DPEC dispute are still unresolved and a trial is scheduled to begin July 8, 2013.[10] Base year expenses included various costs associated with the dispute. According to RMP's response to OCS Data Request 14.4, Confidential Attachment OCS 14.4 -2, base year expenses include *****BEGIN CONFIDENTIAL***** [redacted] *****END CONFIDENTIAL*****

**Q. SHOULD THE ADDITIONAL COSTS IDENTIFIED ABOVE ALSO BE REMOVED FROM THE TEST YEAR?**

A. Yes, they should. The costs recorded in the base year for this matter, which remain in the escalated test year amounts in RMP's filing, should not be included in rates. Since the arbitration rulings against PacifiCorp found that the capital projects were not consistent with "Reasonable Utility Practice" resulting in DPEC not being required to fund its portion of the capital costs, the costs incurred by PacifiCorp in the matter should not be

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[10] Responses to OCS Data Requests 14.3 and 14.4.

incorporated in base rates. These costs are removed on Exhibit OCS 3.18D.

**Q. DO YOU HAVE ANY CONCERNS WITH HOW THE COMPANY IS RECORDING THE LEGAL COSTS ASSOCIATED WITH THIS MATTER ON ITS BOOKS?**

A, Yes. According to the response to DPU 10.11, Attachment DPU 10.11, at page 4 of 8, PacifiCorp recorded legal costs for this matter, as well as several other legal matters, in Account 557. The attachment indicates that the expenses in Account 557 include various legal matters, such as the Deseret dispute, Klamath Settlement, Grant PUD Declaratory Order and USA Power v. Williams. Typically legal costs are found in Account 923 – Outside Services. In fact, PacifiCorp has included the legal costs associated with other cases in Account 923 on its books.

The FERC Uniform System of Accounts for Electric Utilities ("FERC USOA") describes costs to be recorded in Account 557 – Other Expenses, as follows:

> A. This account shall be charged with any production expenses including expenses incurred directly in connection with the purchase of electricity, which are not specifically provided for in other production expense accounts. Charges to this account shall be supported so that a description of each type of charge will be readily available.
>
> B. Recoveries from insurance companies, under use and occupancy provisions of policies, of amounts in reimbursement of

> excessive or added production costs for which the insurance company is liable under the terms of the policy shall be credited to this account.

By recording the costs associated with various legal matters in Account 557 – Other Expenses, the costs may be less transparent for regulators than would be the case if they were recorded with the other legal costs in Account 923 – Outside Services on PacifiCorp's books.

**Q. ARE THERE ADDITIONAL COSTS FOR LEGAL MATTERS RECORDED IN ACCOUNT 557 DURING THE BASE YEAR THAT SHOULD BE REMOVED?**

A. Yes. According to the response to DPU 10.11, Attachment DPU 10.11, at page 4, the legal expenses recorded in Account 557 during the base year includes costs associated with the "USA Power v. Williams" case. This would be for *USA Power LLC; USA Power Partners, LLC; and Spring Canyon Energy, LCC vs. PacifiCorp; Jody L. Williams and Holme, Roberts and Owen, LLP*, which pertains to USA Power's development of an air-cooled, natural gas-fired power plant project to be built in Mona, Utah. On May 21, 2012, a Salt Lake City jury returned a verdict in the matter, awarding $133,899,391 against PacifiCorp and Holme Roberts & Owen law firm in trade secret misappropriation and breach of fiduciary duty. A copy of a press release issued on the verdict, as well as the Special Verdict Form in the case, is attached to this testimony as Exhibit OCS

3.20D. The costs recorded in the base year and thus included in the escalated test year incurred by PacifiCorp for this matter should be removed.

**Q. WHAT ADDITIONAL ADJUSTMENTS SHOULD BE MADE TO REMOVE THE COSTS FOR THE USA POWER MATTER?**

A. I am unable to quantify an adjustment at this time. As of the time this testimony was prepared, OCS Data Request Set 30, which seeks additional information regarding the amount included in the test year for this matter as well as additional information on other legal costs recorded in Account 557 was outstanding.

**Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?**

A. Yes.