Witness OCS – 3D

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of	**)**	**Docket No. 13-035-184**
Rocky Mountain Power for Authority to	**)**	
Increase Its Retail Electric Utility Service	**)**	**Direct Revenue**
Rates In Utah and for Approval of Its	**)**	**Requirement Testimony**
Proposed Electric Service Schedules	**)**	**of Donna Ramas**
And Electric Service Regulations	**)**	**For the Office of**
	)	**Consumer Services**

REDACTED

May 1, 2014

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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 Principal at Ramas Regulatory Consulting, LLC, with offices at 4654 Driftwood Drive, Commerce Township, Michigan 48382.

Q. HAVE YOU PREPARED A SUMMARY OF 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. I 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 3.18D, which are attached to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I present the OCS' overall recommended revenue requirement for RMP. I also sponsor specific adjustments to the Company's filing for the future test period ending June 30, 2015. 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 of 9.20% presented by OCS witness Daniel Lawton, as well as specific adjustments recommended by OCS witness Philip Hayet. At the end of this testimony, I also address the proposal presented in RMP witness Gregory N. Duvall's testimony regarding the tracking of operation and maintenance expenses and capital expenditures associated with the Energy Imbalance Market ("EIM") in the Energy Balancing Account ("EBA").

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, consistent with RMP's presentation.

In preparing Exhibit OCS 3.1D, I used the Company's Jurisdictional Allocation Model, flowing each of the OCS recommended adjustments through the model as well as applying the OCS recommended rate of return. In flowing adjustments through the model, I also included the impact of the net power cost update filed by RMP on April 10, 2014, as Mr.

Hayet's recommended adjustments begin with the Company's April 10, 2014, updated net power costs.

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. 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.

Exhibits OCS 3.3D through 3.18D present each of the adjustments recommended in this testimony. 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.

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 $76,252,101 based on the 2010 Protocol allocation method. The $76,252,101 does not include the impact of RMP's April 10, 2014, Power Cost Update which reduced net power costs by $4,962,705 on a Utah basis. Based on the OCS' analysis, the Company's request is significantly overstated by an amount of $80,898,198. As shown on Exhibit OCS 3.1D, page 1 of 3, the Office of Consumer Services recommends a decrease in the current level of Utah revenue requirement of $4,646,097.

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

A. I first present my recommended adjustments to net operating income. I then discuss my recommended adjustments to rate base. Finally, I address the Company's proposal to track certain costs associated with the EIM through the EBA.

NET OPERATING INCOME

Impact of Employee Reductions on Labor Costs

Q. WHAT EMPLOYEE COMPLIMENT IS THE PRO FORMA TEST YEAR LABOR COSTS BASED ON?

A. The labor costs included in the future test year ending June 30, 2015, is based on the employee compliment that existed during the base year ended June 30, 2013. For example, in calculating the test year regular, overtime and premium time labor costs, RMP began with the actual amounts recorded in each month of the base year ended June 30, 2013. Thus, the labor costs included in the test year are based on the number of Company employees that existed during the base year. The base year monthly labor costs were then escalated for various salary and wage increases. The impact of the wage increases granted during the base year were annualized and both known and projected wage increases that occur subsequent to the base year through the end of the test year were included. The only adjustment made to the base year employee compliment was for a four employee reduction that was included in the adjustment made by RMP in Exhibit RMP__(SRM-3), page 5.3, for the closure of the Little Mountain Plant that occurred in May 2013.

Q. WHAT HAS HAPPENED TO THE EMPLOYEE COMPLIMENT FROM THE START OF THE BASE YEAR THROUGH THE PRESENT TIME?

A. The full time equivalent ("FTE") employee count at PacifiCorp declined significantly throughout the base year and subsequent to date. I have provided the number of FTE employees for each month, July 2012 through January 2014, on Exhibit OCS 3.3D, at page 3.3.1. Page 3.3.1 also shows the monthly change in the employee count for the same period. As shown on page 3.3.1 the FTE employees at PacifiCorp consistently declined each and every month throughout the base year, with the reduction continuing after the base year. The FTE employees totaled 5,558.5 in the first month of the base year, declined to 5,364.5 by the end of the base year and declined even further to 5,334.5 FTE employees in January 2014. This is a reduction of 224 employees from the start of the base year to the most recent level provided by RMP.

Q. WHAT EMPLOYEE COMPLIMENT IS FACTORED INTO THE TEST YEAR IN THIS CASE?

A. The effective employee compliment included in RMP's test year labor costs is based on the average base year employee compliment of 5,464 employees less the 4 employees removed by RMP in the Little Mountain adjustment, or 5,460 employees (5,464 – 4). The individual monthly amounts that make up the average base year FTE employees of 5,464 are shown on Page 3.3.1 of Exhibit OCS 3.3D.

Q. IS THE AVERAGE EMPLOYEE COMPLIMENT THAT EXISTED DURING THE BASE YEAR ENDED JUNE 30, 2013 REFLECTIVE OF THE TEST YEAR EMPLOYEE COMPLIMENT?

A. No, it is not. As indicated above, the PacifiCorp FTE employee compliment was 5,334.5 as of January 2014, the most recent actual count provided by RMP. As shown on Exhibit OCS 3.3D, page 3.3.1, the January 2014 FTE employee count is 125.5 FTE employees lower than the FTE employee count factored into the test year in this case (5,460 – 5,334.5 = 125.5). The actual employee compliment as of January 2014 is 2.30% lower than the FTE employee level included in the test year (125.5 / 5,460 = 2.30%). In response to OCS Data Request 4.4, RMP stated:

"There are no plans to increase or decrease the current full time equivalent level in the organization." Thus, based on the Company's current plans as expressed in the response, the current employee level would be more reflective of the employee compliment that will exist during the test year.

Q. HAVE YOU CALCULATED THE IMPACT OF THE REDUCTION IN THE FTE EMPLOYEE COMPLIMENT ON THE TEST YEAR LABOR COSTS INCLUDED IN RMP'S FILING?

A. Yes. As indicated above, the current FTE employee compliment is 2.30% lower than the amount incorporated in the test year labor costs in RMP's filing. The labor and incentive costs, employee benefit costs (i.e., medical, dental, vision, etc.), and payroll tax costs included in RMP's labor cost adjustment would all be impacted by the employee level. Exhibit OCS 3.3.D, page 3.3.2 identifies the amount of labor costs included in RMP's labor cost adjustment that are impacted by the employee level as $677,790,175 on a total Company basis. Exhibit OCS 3.3D shows that reducing these costs by the 2.30% FTE employee reduction results in a $12,229,161 reduction to the labor costs. Thus, I recommend that the forecasted test year labor costs be reduced by $12,229,161. As shown on Exhibit OCS 3.3D, after removing the portion that is capitalized and the portion allocated to non-utility, test year expenses should be reduced by $8,684,487 on a total Company basis and $3,685,197 on a Utah basis.

<u>Remove Employee Severance Expense</u>

Q. DID RMP INCUR ANY CHARGES DURING THE BASE YEAR ENDED JUNE 2013 FOR EMPLOYEE SEVERANCE COSTS?

A. Yes. Base year costs include $337,750 for severance payments. The $337,750 was carried forward by RMP into the test year ending June 30, 2015. The response to OCS Data Request 4.8 indicates that the costs included in the test year are related to an elimination of some positions in the latter part of 2012, resulting in severance payments. This explanation is consistent with the reduction of employees that occurred during the base year discussed above.

Q. HOW DOES THE AMOUNT INCLUDED IN THE TEST YEAR FOR SEVERANCE PAYMENTS COMPARE TO AMOUNTS INCURRED IN PRIOR PERIODS?

A. Filing Requirement R746-700-22.D.19 identifies the severance expense for the twelve months ended June 2012 as $65,488. The amount recorded during the base year is higher than the prior year level.

Q. HAS THE COMPANY PROVIDED ANY INFORMATION INDICATING THAT IT WILL INCUR SEVERANCE COSTS DURING THE TEST YEAR?

A. No, not to my knowledge. In response to OCS Data Request 4.4, RMP indicated that there are "…no plans to increase or decrease the current full time equivalent level in the organization."

Q. DO YOU RECOMMEND THAT THE SEVERANCE COSTS BE REMOVED FROM THE TEST YEAR?

A. Yes. These appear to be non-recurring costs that were booked during the base year ended June 2013. Absent RMP providing information demonstrating that a similar level of severance costs will be incurred during the test year, I recommend that the costs, totaling $337,750, be removed from the test year. As shown on Exhibit OCS 3.4D, after removing the portion that is capitalized and the portion allocated to non-utility, test year expenses should be reduced by $239,852 on a total Company basis and $107,779 on a Utah basis.

<u>Pension Expense</u>

Q. HOW DID RMP FORECAST THE TEST YEAR PENSION COST SHOWN IN EXHIBIT RMP__(SRM-3), PAGE 4.2.2 OF $21,778,500?

A. According to Filing Requirement R746-700-20.C.3.e, the test year pension cost of $21,778,500 includes $10,919,964 for the PacifiCorp Retirement Plan and $10,858,537 for projected contributions to the Union Local 57 pension plan, both of which are on a net of joint venture basis. Filing Requirement R746-700-20.C.3.e shows that the amount of pension cost included in the test year ending June 30, 2015 for the PacifiCorp Retirement Plan was based on a projected net periodic benefit cost of $14,104,494 for the 2014 plan year and $8,321,658 for the 2015 plan year. A 50% factor was applied to each of these amounts to derive the projected test year net periodic benefit cost on a gross basis of $11,213,076. After application of the net of joint ventures factor of 97.386%, the amount included in the test year was $10,919,964. This discussion, and my recommended adjustment, applies to the PacifiCorp Retirement Plan.

Q. DID RMP PROVIDE THE SOURCE OF THE PROJECTED 2014 AND 2015 PENSION NET PERIODIC BENEFIT COST ASSOCIATED WITH THE PACIFICORP RETIREMENT PLAN CONTAINED IN THE MINIMUM FILING REQUIREMENTS?

A. Yes. OCS Data Request 3.16(a) asked RMP to provide all information received from the actuarial firm used by the Company for purposes of determining the 2014 and 2015 PacifiCorp Retirement Plan amounts that were used in determining the pension cost amounts in the filing. The Company provided Attachment OCS 3.16-1, which it identifies as the actuarial results for the pension plan used as the basis for the test year amounts.

Q. WERE YOU ABLE TO TRACE THE 2014 AND 2015 NET PERIODIC BENEFIT COST AMOUNTS IN ATTACHMENT OCS 3.16-1 TO THE 2014 AND 2015 AMOUNTS CONTAINED IN THE MINIMUM FILING REQUIREMENTS THAT WERE USED IN DETERMINING THE TEST YEAR PENSION EXPENSE?

A. The amounts provided in the attachment for 2014 and 2015 did not tie exactly into the amounts incorporated in the minimum filing requirements. For example, the information provided by Confidential Attachment OCS 3.16-1 showed the 2014 net periodic benefit cost as $14,858,000 whereas the minimum filing requirements show the amount as $14,101,494 or 94.9% of the total. Similarly, the 2015 net periodic benefit cost is shown as $8,828,000 whereas the minimum filing requirements show the 2015 amount as $8,321,658. The Company provided the reconciliation in response to UAE Data Request 7.3, Attachment 7.3, which broke down the amounts provided in Attachment OCS 3.16-1 between the mining operation employees and the electric operation employees. The amounts contained in the minimum filing requirements exclude the mining employees that participate in the PacifiCorp retirement plan.

Q. WAS THE COMPANY ASKED TO UPDATE THE PENSION EXPENSE PROJECTIONS?

A. Yes. By January 1, 2014, the Company would have been required to select several of the actuarial assumptions for use in the 2014 pension plan year. Additionally, the actual 2013 plan experience, which impacts both the 2014 and 2015 pension net periodic benefit cost, would be known. Consequently, in OCS Data Request 3.19 RMP was asked to provide the net periodic benefit cost for the test year ending June 30, 2015 that would result if the assumptions used in preparing the filing were revised to include the impact of the actual 2013 plan experience and the actuarial assumptions that were selected for the 2014 plan year for both the 2014 and 2015 pension calculations since these would be the most recent known and measurable assumptions selected by the Company. The Company response referred to OCS Data Request 3.16, Attachment OCS 3.16-3 and stated that "…the Company has not requested its actuaries to provide revised pension expense for 2015 based on the December 31, 2013 re-measurement results." Thus, updated 2015 pension expense projections have not been provided by RMP.

Q. HOW DO THE UPDATED 2014 PENSION COST PROJECTIONS FOR THE PACIFICORP RETIREMENT PLAN COMPARE TO THE AMOUNTS ORIGINALLY USED BY RMP IN PREPARING ITS FILING?

A. Attachment OCS 3.16-3 consists of a report from the actuarial firm used by PacifiCorp, Towers Watson, and is titled "Actuarial Valuation Report Disclosure for Fiscal Year Ending December 31, 2013 and 2014 Benefit Cost under US GAAP." This actuarial valuation report was dated January 2014 and shows the 2014 net periodic benefit cost as $11,641,917, which is $3,206,000 less than the projected 2014 net periodic benefit cost of $14,848,000 used by RMP at the time it prepared the filing. The response to UAE Data Request 7.4, Attachment UAE 7.4, shows that ($183,000) of the updated 2014 net periodic benefit cost is associated with the mining operations; thus, the electric operation portion would be $11,824,917

($11,641,917 + $183,000).[1] The updated net periodic benefit costs associated with the electric operation employees of $11,824,917 is $2,276,577 less than the $14,101,494 assumed in RMP's filing for 2014.

Q. DO YOU RECOMMEND THAT THE IMPACT OF THE LOWER COST PROJECTION PROVIDED BY TOWERS WATSON BASED ON MORE RECENT ACTUAL INFORMATION BE REFLECTED?

A. Yes. Unfortunately, the Company did not ask Towers Watson to also calculate updated 2015 pension net periodic benefit cost projections on their behalf. The actual 2013 pension plan experience will also impact the 2015 pension net periodic benefit costs. Absent RMP providing updated estimates of the 2015 net periodic benefit costs from its actuarial firm as requested in OCS Data Request 3.16, I recommend that test year pension costs be reduced by the reduction in the projected 2014 net periodic benefit costs. As indicated above, the 2014 net periodic benefit cost provided by Towers Watson declined $2,276,577 from the amount considered in preparing the Company's filing for the electric operation employees. After application of the net of joint ventures factor for 2014 of 97.386%, the reduction is $2,217,067 ($2,276,557 x 97.386%).

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[1] For some reason not explained in the response the "net transition obligation" amount of ($823,378) that was included in both the original 2014 net periodic benefit cost forecast and the updated forecast provided in the Confidential Attachment OCS 3.16-1 was not included in the reconciliation provided in the Confidential Attachment UAE 7.4 causing the final Net Periodic Benefit cost in the reconciliation in Confidential Attachment UAE 7.4 to not fully reconcile to the updated forecast provided by the actuarial firm. Consequently, I have assumed that the entire ($823,378) is applicable to the electric operation employees.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND?

A. I recommend that the forecasted test year pension net periodic benefit cost be reduced by $2,217,067 on a net of joint venture basis. As shown on Exhibit OCS 3.5D, after removing the portion that is capitalized and the portion allocated to non-utility, test year expenses should be reduced by $1,574,441 on a total Company basis and $668,102 on a Utah basis.

<u>Post-Retirement Benefits Expense/(Income)</u>

Q. HOW DID RMP FORECAST THE TEST YEAR POST-RETIREMENT BENEFIT COST SHOWN IN EXHIBIT RMP__(SRM-3), PAGE 4.2.2 OF NEGATIVE $907,162?

A. Filing Requirement R746-700-20.C.3.e shows the test year post-retirement benefit cost was based on the net periodic benefit income of ($458,137) for the 2014 plan year and ($1,400,912) for the 2015 plan year. A 50% factor was applied to each of these amounts to derive the projected test year net periodic benefit income on a gross basis of ($929,525). After application of the net of joint ventures factor of 97.594%, the amount included in the test year was ($907,162). Due to the funding position of the post retirement benefit plan, the Company is in an income position (i.e., negative expense amount) instead of an expense position for the electric operations employees.

Q. DID RMP PROVIDE THE SOURCE OF THE PROJECTED 2014 AND 2015 NET PERIODIC BENEFIT INCOME ASSOCIATED WITH THE

POST-RETIREMENT BENEFIT PLAN CONTAINED IN THE MINIMUM FILING REQUIREMENTS?

A. Yes. OCS Data Request 3.18(a) asked RMP to provide all information received from the actuarial firm used by the Company for purposes of determining the 2014 and 2015 post-retirement benefit amounts that were used in determining the amounts incorporated in the filing. The Company provided Attachment OCS 3.18-1, which it identifies as the "…actuarial results for the FAS 106 plan used as the basis for the test year amounts…" OCS Data Request 13.6 asked the Company to reconcile the amounts provided in Attachment OCS 3.18-1 to the amounts provided in the filing requirements at R746-700-20.C.3.e.

The reconciliation, which was provided as Attachment OCS 13.6, showed the actuarially projected 2014 net periodic benefit cost for the post-retirement benefits for mining and electric operations combined as $7,167,000, with $7,625,000 being removed for the mining employees. This left a net periodic benefit income amount of ($458,000) for the electric operations employees which ties to the ($458,137) contained in the filing requirements for 2014. Similarly, the reconciliation showed the actuarially projected 2015 net periodic benefit cost for the post-retirement benefits for the mining and electric operations employees combined as $6,623,000, with $8,024,000 being removed for the mining employees. This left a net periodic benefit income amount of ($1,401,000) for the electric operations employees which ties to the ($1,400,912) contained in the filing requirements for 2015. The table below shows the total projected amounts for 2014 and 2015 with the split between the mining and the electric operations employees in each of those periods.

	2014	2015
Net Periodic Benefit Cost - Mining Employees	$ 7,625,000	$ 8,024,000
Net Periodic Benefit Income - Electric Operations	$ (458,000)	$ (1,401,000)
Total Net Periodic Benefit Cost/(Income)	$ 7,167,000	$ 6,623,000

Q. WAS THE COMPANY ASKED TO UPDATE THE POST-RETIREMENT BENEFIT PLAN EXPENSE PROJECTIONS?

A. Yes. Similar to the pension plan previously discussed, the Company would have also been required to select several of the actuarial assumptions for use in the 2014 plan year for its post retirement benefit plan. Additionally, the actual 2013 plan experience, which impacts the 2014 and 2015 net periodic benefit cost/(income), would be known. OCS Data Request 3.21 asked RMP to provide the actuarial assumptions that were selected for use in the 2014 plan year. The data request also asked RMP to provide the revised post-retirement benefit plan expense for 2014, 2015 and the test year ending June 30, 2015 that would result if the assumptions used in preparing the filing were revised to include: (1) the impact of the actual 2013 plan experience; and (2) the actuarial assumptions that were selected for the 2014 plan year for both the 2014 and 2015 post-retirement benefit plan calculations. The Company response referred to OCS Data Request 3.18, Attachment OCS 3.18-2 and stated that "…the Company has not requested its actuaries to provide revised FAS 106 expense for 2015 based on the December 31, 2013 re-measurement results." Thus, updated 2015 expense projections have not been provided by RMP.

Q. HOW DOES THE UPDATED 2014 POST-RETIREMENT PLAN COST PROJECTIONS COMPARE TO THE AMOUNTS ORIGINALLY USED BY RMP IN PREPARING ITS FILING?

A. Attachment OCS 3.18-2 consists of a report from the actuarial firm used by PacifiCorp, Towers Watson, for the PacifiCorp Postretirement Welfare Plan and is titled "Actuarial Valuation Report disclosure for Fiscal Year Ending December 31, 2013 and 2014 Benefit Cost under US GAAP." This actuarial valuation report was dated January 2014 and shows the 2014 net periodic benefit cost as $5,259,256, which is $1,907,744 less than the projected 2014 net periodic benefit cost of $7,167,000 used by RMP at the time it prepared its filing. It is also less than the projected 2015 net periodic benefit cost of $6,623,000 used in the filing.

Q. HOW DOES THIS $1,907,744 REDUCTION TO THE PROJECTED 2014 AMOUNT TRANSLATE TO THE PORTION OF THE NET PERIODIC BENEFIT COST/(INCOME) APPLICABLE TO ELECTRIC OPERATIONS EMPLOYEES?

A. The actuarial information provided by RMP in response to OCS Data Request 3.18 did not break down the updated 2014 net periodic benefit costs between the mining employees and the electric operations employees. However, a breakdown between the electric operations and the mining operations was provided in response to UAE Data Request 7.2, Attachment UAE 7.2. The attachment shows that $6,064,000 of the updated 2014 net periodic benefit costs is associated with the mining operations; thus, the electric operation net periodic benefit income would be ($804,744) ($5,259,256 - $6,064,000).[2] The updated net periodic benefit income associated with the electric operation employees of ($804,744) is $346,607 greater than the ($458,137) assumed in RMP's filing for 2014.

Q. DO YOU RECOMMEND THAT THE IMPACT OF THE LOWER COST PROJECTION PROVIDED BY TOWERS WATSON, WHICH WAS BASED ON MORE RECENT ACTUAL INFORMATION, BE REFLECTED?

A. Yes. Unfortunately, the Company did not ask Towers Watson to also calculate updated 2015 net periodic benefit cost projections on their behalf. The actual 2013 post-retirement benefit plan experience will also impact the 2015 net periodic benefit income. Absent RMP providing

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[2] For some reason not explained in the response the "amortization of regulatory (liability)/asset" amount of $489,171 that was included in both the original 2014 net periodic benefit cost forecast and the updated forecast provided in the Attachment OCS 3.18-2 was not included in the reconciliation provided in the Confidential Attachment UAE 7.2 causing the final Net Periodic Benefit cost in the reconciliation in Attachment UAE 7.2 to not fully reconcile to the updated forecast provided by the actuarial firm. Consequently, I have assumed that the entire $489,171 is applicable to the electric operation employees.

updated estimates of the 2015 net periodic benefit income from its actuarial firm, I recommend that test year net periodic benefit income be increased by the increase in the projected 2014 net periodic benefit income. As indicated above, the 2014 net periodic benefit income based on the updated amounts provided by Towers Watson increased $346,607 from the amount considered in preparing the Company's filing for the electric operation employees. After application of the net of joint ventures factor for the test year of 97.594%, the increase is $338,268 ($346,607 x 97.594%).

Q. WHAT ADJUSTMENT DO YOU RECOMMEND AT THIS TIME?

A. I recommend that the forecasted test year pension net periodic benefit income be increased by $338,268 on a net of joint venture basis. As shown on Exhibit OCS 3.6D, after removing the portion that is capitalized and the allocation to non-utility, test year expenses should be reduced by $240,220 on a total Company basis and $101,935 on a Utah basis.

<u>401(k) Administration Costs</u>

Q. ARE THERE ANY ADDITIONAL TEST YEAR LABOR COSTS THAT YOU RECOMMEND BE ADJUSTED?

A. Yes. During the base year, the Company recorded $504,846 on its books for 401(k) administration costs. RMP carried the base year cost of $504,846 forward to the test year. The amount recorded during the base year is not reflective of a typical annual expense level for the 401(k) administrative costs, thus I recommend they be reduced to a more typical annual cost level.

Q. WOULD YOU PLEASE ELABORATE ON THE REASONS WHY THE 401(K) ADMINISTRATIVE COSTS ARE NOT REFLECTIVE OF A TYPICAL ANNUAL COST LEVEL?

A. Yes. Filing Requirement Attachment R746-700-22.D.19 shows that the 401(K) administrative costs in the year prior to the base year, or the year ended June 2012, were $77,570. Similarly, Exhibit RMP__(SRM-3) from the last rate case, Docket No. 11-035-200, at page 4.2.2 shows the 401(k) administrative costs for the year ended June 2011 as $190,122. OCS Data Request 4.8 asked RMP to explain what factors caused the amount of 401(k) administrative costs to increase from $77,570 for the twelve months ended June 2012 to the base year level of $504,846. In response, the Company indicated that charges for the two periods were comparable; but that the twelve months ended June 2011 included $400,000 more credits against the charges that result from reimbursement of costs from the 401(K) trust. The response also indicated that the costs for the year ended December 31, 2013 were ($42,728.19) as a result of credits received from the trust. Based on this information, the base year cost level is not reflective of a typical annual cost level due to the timing of when the credits from the 401(K) trust are received.

Q. HAVE YOU ESTIMATED A MORE TYPICAL ANNUAL 401(K) ADMINISTRATIVE COST LEVEL?

A. Yes. Given the fact that the timing of when the reimbursements from the trust are received can have a fairly large impact on the amount recorded in any given twelve-month period, I recommend that the test year 401(K) administrative costs be based on the average amount recorded for the three-years ended June 2013. As shown on Exhibit OCS 3.7D, the three-year average administrative cost booked by PacifiCorp was $257,513, which is $247,333 less than the $504,846 included in the test year. Thus, I recommend that test year labor costs be reduced by $247,333 in order to normalize the level of 401(k) administrative costs included in the test year. As shown on Exhibit OCS 3.7D, after removal of the portion of the reduction that is applicable to capital and non-utility, test year expenses should be reduced by $175,642 on a total Company basis and $74,533 on a Utah basis.

Collection Costs

Q. HAVE ANY CHANGES IN RMP'S COLLECTION POLICIES BEEN IMPLEMENTED IN UTAH THAT WOULD IMPACT TEST YEAR COLLECTION COSTS?

A. Yes. On August 2, 2013, the Commission approved an update to Electric Service Regulation No. 3 – Electric Service Agreements. The update results in the customer now being responsible for any reasonable costs associated with collecting unpaid accounts, including court costs, attorney's fees and collection agency fees. This change and the date of approval were identified by the Company in Filing Requirement R746-700-22.D.39. Thus, the costs are now the responsibility of the individual customers that cause the costs to be incurred and not RMP. During the base year ended June 2013, expenses in FERC Account 903 – Customer Receipts and Collection Expense included $434,331 for costs associated with the collection of unpaid accounts including court costs, attorney's fees and collection agency fees. These costs were escalated by RMP in its filing, resulting in the test year including $449,965.[3] Since the new policy was implemented prior to the start of the test year in this case, I have removed the $449,965 from test year expenses on Exhibit OCS 3.8D.

Q. DOES RMP AGREE THAT THE COSTS SHOULD BE REMOVED FROM THE TEST YEAR EXPENSES IN THIS CASE?

A. Yes. In response to OCS Data Request 4.12, RMP indicated that "The lack of adjustment to remove these expenses was an oversight." The response also indicated that RMP will prepare "…an appropriate adjustment and include it in Rebuttal."

<u>Reduction to Charges from Affiliates</u>

Q. WHAT AMOUNT IS INCLUDED IN THE BASE YEAR AND THE ADJUSTED TEST YEAR FOR CHARGES FROM MIDAMERICAN

[3] Response to OCS Data Request 4.12

ENERGY HOLDING COMPANY ("MEHC") AND MIDAMERICAN ENERGY COMPANY ("MEC") TO PACIFICORP?

A. Many of the charges from MEHC and MEC are recorded on PacifiCorp's books in Account 426.5, which is a below-the-line account that is not included in rates charged to customers. The response to OCS Data Request 3.9, Attachment OCS 3.9-1 shows that the base year included $6,968,161 for charges from MEHC and MEC that were recorded in above the line accounts, predominately in Account 923 – Outside Services Expense. The base year amount was escalated resulting in $7,281,497 being included in the test year on a total PacifiCorp basis and $3,090,139 on a Utah jurisdictional basis.

Q. HAVE ANY RECENT EVENTS TRANSPIRED THAT IMPACT THE AMOUNTS CHARGED TO PACIFICORP FROM MEHC AND MEC?

A. Yes. On December 19, 2013, MEHC completed its acquisition of NV Energy, Inc. As such, a portion of corporate charges incurred by MEHC and MEC will now be allocated to NV Energy, Inc. This will reduce the costs that are allocated from MEHC and MEC to PacifiCorp as NV Energy is now included in the calculation of the allocation factors that are used in allocating the shared corporate costs to affiliates under the Intercompany Administrative Services Agreement.

Q. HAS THE COMPANY PROVIDED THE IMPACT OF THE RECENTLY COMPLETED ACQUISITION BY MEHC ON THE TEST YEAR EXPENSES INCLUDED IN THE FILING?

A. Yes. In response to OCS Data Request 3.9, Attachment OCS 3.9.1, the Company provided its current best estimate of the reduction to the adjusted test year expenses charged from MEHC and MEC to PacifiCorp that result from MEHC's acquisition of NV Energy, Inc. The response provided an estimated reduction to test year expenses of $1,014,774 on a total Company basis. As shown on Exhibit OCS 3.9D, test year expenses should be reduced by the $1,014,774 on a total Company basis and $430,978 on a Utah jurisdictional basis to reflect the reduction in charges from MEHC and MEC that result from MEHC's recent acquisition.

Generation Overhaul Expense

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

A. RMP adjusted the base year generation overhaul expense to reflect a four-year average cost level based on the twelve month periods ended June 2010 through the base year ended June 2013. In deriving its adjustment, RMP used actual overhaul costs for the past four year period on a plant-by-plant basis for the plants that were owned for the entire four-year period. RMP applied a 25% reduction factor to the Carbon plant since the plant is anticipated to be retired in April 2015. The Company then escalated the resulting annual overhaul expense amounts to June 2013 dollars, applying escalation factors that ranged from 1.77% to 9.31%. RMP then added a four-year average of projected future overhaul costs for the new Lake Side 2 plant that is scheduled to be completed and placed into service in June 2014.

RMP's generation overhaul expense adjustment resulted in an $8,346,416 ($3,557,936 Utah) increase to the recorded base year overhaul expense. The inclusion of overhaul costs in rates at an average, normalized level is consistent with past Commission decisions. However, RMP's application of escalation factors to the historical balances prior to averaging the cost is not.

Q. WHY ARE OVERHAUL EXPENSES BASED ON A FOUR-YEAR AVERAGE COST LEVEL?

A. The amount of expense incurred for the overhaul of generation facilities can vary significantly from year-to-year and from generation unit to generation unit. The amount of overhaul costs that are capitalized versus expensed will also vary between overhauls and between units depending on the specific work done during a particular overhaul. In order to ensure that base rates are not set at a level to include either an abnormally high level or an abnormally low level of generation overhaul expense, overhaul expense has historically been incorporated in rates based on an average level using a four year period in determining the average.

Q. HOW DOES RMP'S METHODOLOGY OF DETERMINING THE HISTORICAL AVERAGE OVERHAUL EXPENSE TO INCLUDE IN

RATES 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 expense in rates based on a four-year average historical 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 historical costs in determining the normalized cost level for inclusion in rates. This is acknowledged by Mr. McDougal in his direct testimony in this case at page 23, lines 511 through 518.

In the last two rate cases, Docket Nos. 10-035-124 and 11-035-200, parties reached settlements that did not specifically address the method for normalizing generation overhaul costs in rates. Therefore, the normalizing treatment was not addressed in the Commission's Orders in either of those cases. In Docket No. 10-035-124, RMP did not escalate the historical costs in its filing, but instead followed the Commission approved methodology. However, the Division did recommend that the historical costs be escalated prior to determining the average, normalized balance of overhaul costs to include in rates in its pre-filed direct testimony in Docket No. 10-035-124. In the last rate case, Docket No. 11-035-200 both RMP and the Division recommended that the historical costs be escalated prior to determining the average, and RMP used this same approach of escalating the costs in this docket. The OCS has consistently recommended that the costs not be escalated prior to averaging.

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:

> 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 WAS THE ISSUE ADDRESSED BY THE COMMISSION 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 advocated against escalation of the historical amounts. 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 DPU's surrebuttal testimony, their position was modified 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 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 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?

A. In my opinion, the information submitted in this case, and in the prior case, does not justify changing the Commission's position with regards to whether or not the historic overhaul costs should be escalated prior to determining the normalized cost level. The Company has not demonstrated that their approach of applying escalation factors to the historical data in normalizing overhaul expenses provides reasonable results over time. Beginning at page 23 of his direct testimony, at line 523, Mr. McDougal indicates that new evidence in support of the escalation of the costs has been presented in the last two rate cases that were settled, so the "new evidence" had not been heard by the Commission. On page 24 of his testimony, Mr. McDougal then quotes from the DPU's testimony in Docket 11-035-200 which stated:

> First, economic theory suggests that in order to compare two values separated by time, the values need to have a common monetary base. That is, the values should be expressed in real terms, where the effects of inflation are taken into account, as opposed to nominal terms. Comparing values expressed in nominal terms – ignoring inflation – can lead to erroneous conclusions.

Mr. McDougal then expresses his agreement with the DPU's above quoted statement and provides an example comparing inflated (i.e., escalated) and non-inflated amounts. Obviously, the amounts to which the inflation factors are applied are higher than the amounts in which the inflation was not applied in Mr. McDougal's examples. This is not new or compelling evidence that should justify the change in treatment with regards to this issue.

Q. PLEASE EXPLAIN WHY THE DESCRIPTION OF INFLATION AND THE IMPACTS OF INFLATION ON DOLLARS DOES NOT PERSUADE YOU TO CHANGE YOUR POSITION.

A. The hypothetical example presented by Mr. McDougal in his testimony focuses on the pressures of inflation on costs. However, it does not factor in the productivity offsets that have been and will continue to be realized by RMP. While some of the costs of the materials used in overhauling the generation units may be subject to inflation pressures, and the wages of employees performing the work may be increasing over time, there are also productivities that are realized. The experience gained from prior overhauls can be applied in future overhauls to make future overhauls more efficient. Lessons are learned and retained. Additionally, over the years RMP has undertaken several cost saving measures and strives to keep its costs under control. Mr. McDougal's hypothetical example may address inflation and compare different methods of inflating costs, but it is not specific to the overhaul expenses realized by RMP. It also does not address the productivities that are gained as a result of regularly performing overhauls on the various generation facilities and cost savings measures that are implemented by the Company.

I recommend that the Commission re-affirm, once again, that the historical generation overhaul expenses should not be escalated for purposes of normalizing generation overhaul expense to include in base rates.

Q. WHAT ADJUSTMENT IS NEEDED TO REMOVE THE IMPACTS OF THE ESCALATION FACTORS APPLIED BY RMP ON THE HISTORICAL COSTS?

A. As shown on Exhibit OCS 3.10D, test year expenses should be reduced by $1,467,160 ($625,426 Utah) to remove the impact of the Company's proposed escalation of the historical costs prior to normalization.

<u>Remove Carbon Plant Overhaul Expense</u>

Q. IN YOUR TESTIMONY ABOVE, YOU DISCUSSED RMP'S GENERATION OVERHAUL EXPENSE NORMALIZATION ADJUSTMENT. THE COMPANY CURRENTLY PROJECTS THAT THE CARBON PLANT WILL BE RETIRED IN APRIL 2015. ARE OVERHAUL COSTS FOR THE CARBON PLANT INCLUDED IN RMP'S NORMALIZATION ADJUSTMENT?

A. Yes, but at a reduced amount. In Exhibit RMP__(SRM-3), at page 4.8.2, RMP removed 25% of the overhaul expenses incurred at the Carbon plant during the four year period ended June 2013 prior to applying the annual escalation factors. In describing the purpose of the adjustment, footnote 3 of the exhibit states: "Carbon plant expense is scaled back 25% (April to June 2015) in the 4year average totals due to the plant's scheduled April 2015 retirement." Thus, 75% of the Carbon plant overhauls expenses incurred during the four years ended June 2013, plus the escalation of those historical costs, are factored into the normalized overhaul expense in RMP's filing.

Q. WHAT IMPACT DOES RMP'S INCLUSION OF 75% OF THE CARBON PLANT OVERHAUL COSTS HAVE ON THE NORMALIZED GENERATION OVERHAUL EXPENSE THE COMPANY IS SEEKING TO INCLUDE IN THE TEST YEAR IN THIS CASE?

A. As shown on Exhibit OCS 3.11D, page 3.11.1, the normalized overhaul expense includes $633,903 associated with the Carbon plant before the application of the escalation factors and $641,230 on an escalated basis.

Q. SINCE THE PLANT IS BEING RETIRED DURING THE TEST YEAR, WILL PACIFICORP INCUR OVERHAUL EXPENSES AT THE CARBON PLANT DURING THE TEST YEAR OR IN ANY PERIOD AFTER THE TEST YEAR?

A. No, it will not. I recommend that the Carbon plant overhaul expense be removed from the normalized generation overhaul expense included in the test year. RMP has included an adjustment to add a projected four-year average overhaul expense level for the new Lake Side 2 plant that is projected to be placed into service in June 2014. Similarly, in prior rate cases in which new generation plants have been added and were not included in service during the entire historical four-year average generation overhaul expenses period, adjustments have been made to project a four-year average overhaul expense level for the new plants based either on all projected amounts or a combination of actual and projected amounts. On the opposite side, the overhaul expense for plants that are being retired, such as the Carbon plant, for which the Company will not incur overhaul expense during the test year or subsequent years should be removed.

Q. WHAT ADJUSTMENT IS NEEDED TO REMOVE THE CARBON PLANT OVERHAUL EXPENSE FROM THE TEST YEAR?

A. As shown on Exhibit OCS 3.11D, test year expenses should be reduced by $633,903 ($270,222 Utah) to remove the Carbon plant overhaul expense from the normalized generation overhaul expense. If the Commission reverses its prior decisions and rejects my recommended removal of the escalation from the normalized overhaul expense, discussed previously, then the adjustment should be increased to $641,230 ($273,346 Utah) to ensure that the escalation applied to the historical Carbon balances is also removed.

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

Q. THE COMPANY'S ADJUSTMENT FOR INCREMENTAL O&M EXPENSE FOUND AT EXHIBIT RMP__(SRM-3), PAGE 4.9.1, IS IDENTIFIED AS "INCREMENTAL O&M (EXCLUDING LABOR, NET

POWER COSTS, AND OVERHAULS)". WHAT IS THE PURPOSE OF THIS DISTINCTION?

A. The net power costs, generation overhaul expenses and labor costs are adjusted separately in the Company's filing. Thus, in its adjustment to the generation O&M expenses, the labor, net power costs and overhaul expenses are excluded from the adjustment, with the exception of the partner operated plants which include the labor and non-labor costs. For ease of this discussion, in this section of testimony when I refer to the "generation O&M expense", I am referring to the generation operation and maintenance expense associated with the PacifiCorp operated coal, gas and geothermal generation plants exclusive of the labor, net power costs and overhaul expense and the partner operated generation plants exclusive of net power costs and overhaul expense. I am not addressing the hydro generation plants or the wind generation plants in this section of my testimony.

Q. WOULD YOU PLEASE BRIEFLY DESCRIBE HOW THE COMPANY FORECASTED THE GENERATION O&M EXPENSE FOR THE COAL, GAS AND GEOTHERMAL GENERATION PLANTS, INCLUDING THE PARTNER OPERATED GENERATION PLANTS, IN PRIOR RATE CASES?

A. Historically, RMP applied escalation factors to the base year generation O&M expenses in order to determine the test year expense with a few specific adjustments to its base year generation O&M expenses associated with either the addition of new facilities, substantive changes made to specific facilities, or known contract changes. For example, in Docket No. 10-035-124, RMP made an adjustment to incremental generation O&M to reflect 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 relative to 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.

RMP changed its approach in the most recent prior rate case, Docket No. 11-035-200. In that case, RMP adjusted the generation O&M expense to the budgeted test year level on a plant by plant basis. In other words, plant operating budgets were used in projecting the test year amounts instead of a build-up of the base year costs. In that case, when compared to the escalated base year cost level, the adjustment resulted in reductions to the generation O&M expense at the Company-owned plants and a $4.95 million increase in the partner operated generation O&M expense. The net result, which was provided on Exhibit RMP__(SRM-3), page 4.9.1 in that case, was a $10.14 million increase above the base year level of $174,036,384, which exceeded the escalation adjustment associated with the same plants by $935,256.

Q. SINCE THE MOST RECENT PRIOR RATE CASE WAS THE FIRST CASE IN WHICH RMP BASED THE GENERATION O&M EXPENSE ENTIRELY ON BUDGETED AMOUNTS ON A PLANT BY PLANT BASIS, DID YOU REVIEW THE ACCURACY OF THOSE PROJECTIONS?

A. Yes. In the prior rate case, the base year was the twelve months ended June 2011 and the test year was the twelve months ended May 2013. Thus, the generation O&M expense in that case was based on the forecasted costs for the twelve months ended May 2013 for each plant. The base year in this case is the twelve months ended June 2013; therefore, there is only one month difference between the timeframe of the projected test year in the last rate case and the actual base year in this case. Given the close proximity with only one month difference between the two periods, I compared the forecasted test year generation O&M expense in the last case to the base year in this case. As shown on Exhibit OCS 3.12D, page 3.12.1, the actual generation O&M expense was considerably less than the budgeted amounts incorporated in RMP's filing in the last rate case. Page 3.12.1 provides the comparison on a plant by plant basis. The table below summarizes the variance for the PacifiCorp operated coal plants; the PacifiCorp operated gas and geothermal plants; and for the partner operated plants[4]:

	12 Months Ended May 2013 Forecast	12 Months Ended June 2013 Actual	Favorabe/ (Unfavorable) Variance	% Variance
Coal Fired Generation O&M Expense	112,016,109	108,042,913	3,973,196	3.55%
Gas & Geothermal Generation O&M Expense	10,484,140	11,226,714	(742,574)	-7.08%
Partner Operated Generation O&M Expense	61,679,335	58,112,150	3,567,185	5.78%
Total Generation O&M Expense	184,179,584	177,381,777	6,797,807	3.69%

As shown above, the actual generation O&M expenses for the year ended June 2013 of $177,831,777 were approximately $6.8 million less than the amount the Company forecasted for the test year ended May 2013 of $184,179,584, with a variance of 3.69%. In fact, the actual expenses for the year ended June 2013 were closer to the base year level in the prior rate case, or the year ended June 2011, of $174,036,385 than they were to the forecasted test year amount in that case of $184,179,584.

Q. DID YOU ASK FOR AN EXPLANATION OF THE LARGE VARIANCES BETWEEN THE FORECASTED TEST YEAR COSTS IN THE LAST CASE AND THE ACTUAL BASE YEAR COSTS IN THIS CASE?

A. OCS Data Request 4.25 asked the Company to explain some of the larger variances found with some of the specific plants. In explaining the comparison of the forecasted generation O&M expense for the Dave

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[4] The Cholla plant operator instituted a change in their billing process that resulted in a delay in some costs being charged to PacifiCorp, impacting base year expenses. The base year Cholla generation O&M expenses were increased by $1,656,330 in the above analysis to include all expenses applicable to the base year.

Johnston plants of $18.5 million to the actual cost of $15.7 million, the Company responded that: "Actual costs were lower than forecast due to favorable plant operations requiring less start-up fuel, timing of non-overhaul maintenance projects and maintenance work that met property retirement unit criteria and was capitalized rather than charged to maintenance expense." In explaining the comparison of the forecasted expense for the Wyodak plant of $6.5 million as compared to the actual expense of $5.9M, the response was: "Actual costs were lower than forecast due to favorable plant operating conditions resulting in less forced outage work and few start-ups." Similarly, in explaining the comparison of the forecasted generation O&M expense at the Colstrip plant of $8.3 million as compared to the actual costs of $7.1 million, the response was: "Actual costs were lower than forecast due to favorable plant operating conditions resulting in a favorable run of the units with lower costs for start-up fuel and timing of maintenance." In explaining the variance at the Cholla plant, the Company referenced a billing delay by the plant operator that was trued-up in early 2014. However, even when the portion of the true-up applicable to the base year is factored in, the actual Cholla generation O&M expense was still approximately $800,000 lower than the amount projected in the prior case.

Q. HOW DOES THE PROJECTED INCREASE IN GENERATION O&M EXPENSE IN THIS CASE COMPARE TO THE PROJECTED INCREASE FACTORED INTO THE PRIOR RATE CASE?

A. As indicated above, in the prior rate case RMP projected that the generation O&M expense would increase by $10.14 million between the base year and the test year, going from $174,036,385 to $184,179,584, which is an increase of 5.8%. In the current case, RMP projects the generation O&M expense will increase by $20,334,556, going from the base year amount of $175,725,447 to $196,070,003, which is an increase of 11.6% in a two year period. Exhibit RMP__(SRM-3), page 3.12.1 shows that the application of inflation to the base year level of costs would increase the generation O&M expense by $5,512,190, compared to the $20,334,556 increase proposed by RMP. Thus the Company's proposed adjustment exceeds the inflation adjustment impacts by $14,832,366 ($20,334,556 - $5,512,190).

Q. IN YOUR OPINION, HAS THE COMPANY SUPPORTED THE PROJECTED $20,334,556 INCREASE IN GENERATION O&M EXPENSE CONTAINED IN ITS FILING?

A. No, it has not. Company witness Dana M. Ralston provides a high level discussion of some of the drivers that would increase the generation O&M expense at the thermal generation plants in this case and provides examples of some of the projected cost changes. The testimony is similar to the testimony he provided in the prior rate case in describing the projected generation O&M expense increases contained in that filing. In order to obtain additional support for the projected test year generation O&M expense of $196,070,000, which is $20.3 million higher than the base year amount, RMP was asked in OCS Data Request 4.24 to "Provide a copy of the budgets, in the most detailed format available, supporting each of the amounts shown in the column titled '12 ME June 2015 forecast.'" These would be the amounts that total the $196,070,000 test year generation O&M expense. The question also asked for a reconciliation of the budgets being provided to the amounts contained in the filing. The response stated:

> Please refer to Confidential Attachment OCS 4.24, which includes the twelve months ended June 2015 budget by functional category. The amounts in the filing and the budget are the same except where noted. Budget amounts are shown in calendar year 2014 dollars and have not been escalated to June 2015 except where noted.

The information provided on the Confidential Attachment for the PacifiCorp owned coal, gas and geothermal plants and the partner operated plants was a very high level listing broken out by functional category with very little information rather than a detailed listing that would support the projected $20.3 million cost increase.

Likewise, UAE Data Request 2.9(a) sought similar information, requesting RMP to "…provide all workpapers and applicable documents, including operating budgets, that show and support the derivation of the values…" for each of the test year generation O&M amounts by plant and to "…provide all relevant calculations in Excel format with working formulas included." The Company's response simply referred to the response to OCS Data Request 4.24 discussed above.

OCS Data Request 19.5 asked for further detail regarding the partner operated plants. The question asked the Company to provide the information that was supplied by the operator to RMP in support of the amounts contained in the test year. The question also asked that if the amounts provided do not tie into the monthly test year amounts by plant, to provide reconciliation between the amounts provided by the operators and the amounts contained in the filing. The Company responded as follows:

> The timing of the budget cycles for the preparation of the Company's plan and that of the partner-operated generation plants do not coincide. In the Company's planning cycle, it is left to compile reasonable projections from prior communications and ongoing information derived from the operators, such as the E&O committee meetings and other communication. Please refer to Confidential Attachment OCS 19.5, which compares the O&M costs included in the Company's plan and submitted on page 4.9.1 to the amounts compiled based on information from the operators of the partner-owned plants.

The confidential attachment consisted of a single page of data with extremely little detail.

Q. DO YOU RECOMMEND THAT THE GENERATION O&M EXPENSE BE ADJUSTED IN THIS CASE?

A. Yes. As discussed above, RMP has not provided a reasonable level of support for the significant increase in the generation O&M expense it has projected in this case. Additionally, a comparison of the forecasted generation O&M expenses in the last rate case to the recent actual amounts does not provide confidence in the accuracy of PacifiCorp's forecasting in the generation O&M expense area. Given the lack of support provided by the Company and the inaccuracy of the prior forecast, I recommend that with the exception of the Carbon, Naughton and Lake Side 1 and 2 generation plants, the test year generation O&M expense be based on the actual base year ended June 2013 amounts increased for escalation. This is similar to how most other accounts are projected by RMP in its filing and in past rate case filings.

Q. WHY DO YOU RECOMMEND THAT THE CARBON, NAUGHTON AND LAKE SIDE 1 AND 2 GENERATION PLANTS BE EXCLUDED FROM YOUR ADJUSTMENT?

A. There are unique and significant circumstances associated with the operation of each of these plants. It is currently projected that the Carbon plant will be retired in April 2015. Since it will not be in operation for the entire test year, I recommend that the test year expense be based on RMP's forecast amount for this plant instead of the escalated base year amount. This is discussed further in the following section of my testimony.

It is also projected that the new Lake Side 2 gas generation facility will be placed into service in June 2014; thus, escalation of the base year expense for Lake Side 1 would not incorporate the costs of the new plant.

Unfortunately, the Company does not separately budget between the two units to allow the two plants to be separated for purposes of the adjustment. As a result, I recommend that the test year expense be based on RMP's forecast amount for Lake Side 1 and 2.

The revenue requirements in RMP's filing were prepared under the assumption that Naughton Unit 3 will cease operations as a coal-fired generating unit in December 2014 and be converted to a gas-fired peaking unit by May 2015. Given the significant down-time for the unit during the test year and the significant change to the unit, the base year expense as escalated for the Naughton units would not incorporate the impact of this significant event. RMP was unable to separate the base year amounts and the forecast between the separate Naughton units. As a result, I recommend that the test year expense be based on RMP's forecast at this time. In RMP's April 10, 2014 Net Power Cost update filing, RMP indicated that if Wyoming grants the Company's request to amend the Naughton unit 3 BART permit before the June 4, 2014 rebuttal testimony date, the Company will update the revenue requirement request in this case as part of its rebuttal filing. If that occurs, I may modify my recommendation with regards to the appropriate amount of Naughton generation O&M expense to incorporate in the test year in this case.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE BASE YEAR GENERATION O&M EXPENSE PRIOR TO THE APPLICATION OF THE ESCALATION FACTORS USED IN RMP'S FILING?

A. Yes. As indicated previously, there was a delay in some of the amounts billed to PacifiCorp from the Cholla plant operator that results in the base year generation O&M expense associated with the Cholla plant being understated. In calculating my recommended adjustment, I increased the base year generation O&M expense for the Cholla unit by $1,656,330 before applying the escalation factors to the base year costs.

Q. WHAT IS THE TEST YEAR GENERATION O&M EXPENSE YOU RECOMMEND BE ADOPTED BY THE COMMISSION IN THIS CASE?

A. As shown on Exhibit OCS 3.12.D, page 3.12.2, I recommend that RMP's forecasted test year generation O&M expense be reduced by $14,340,375 from $196,070,004 to $181,729,629. The calculation, and the comparison to RMP's requested amounts, is provided on a plant by plant basis on page 3.12.2. As shown on Exhibit OCS 3.12D, this adjustment results in a $14,340,375 ($6,113,060 Utah) reduction to test year expenses.

<u>Carbon Plant Non-Labor and Non-Overhaul Expenses</u>

Q. YOU PREVIOUSLY INDICATED THAT YOU DID NOT ADJUST THE PROJECTED TEST YEAR GENERATION O&M EXPENSES (EXCLUDING LABOR, NET POWER COSTS AND OVERHAULS) FOR THE CARBON PLANT. DO YOU HAVE ANY ADDITIONAL

RECOMMENDATIONS FOR THE COMMISSION WITH REGARDS TO THE AMOUNT OF EXPENSE INCLUDED IN RATES FOR THE OPERATION OF THE CARBON PLANT?

A. Yes. In this case, the Company has included its projected test year operation and maintenance expenses for the Carbon plant. However, it is currently projected that the plant will be retired in April 2015. Thus, if rates from this case are in effect for longer than the test year, the costs associated with operating and maintaining the plant will still be collected in rates based on the projected test year expense in this case.

The 2012 GRC Stipulation at paragraphs 46 through 50 indicates, in part, that a Carbon Removal Costs regulatory asset will be established to be recovered from customers from the time the plant is retired through calendar year 2020. That retirement is projected to occur before the end of the test year in this case. In Mr. McDougal's direct testimony, beginning at page 11, line 257, he states: "Concerning the Carbon Removal Costs regulatory asset, the Company is proposing in this case to defer any recovery and amortization of this balance until the next general rate case filing."

Test year generation O&M expenses include $4,472,000 for the operation and maintenance of the Carbon plant, and this amount will continue to be collected in rates after the test year and until rates are set in the next general rate case proceeding. This effectively translates to $372,667 per month being collected from customers ($4,472,000 / 12). Since the generation O&M expenses associated with the Carbon plant will cease when the plant is retired, I recommend that beginning the month after the Carbon plant ceases to provide generation services, $372,667 per month be recorded as an offset in the Carbon Removal Cost regulatory asset. This monthly offset to the regulatory asset should continue until the rates established in the next general rate case go into effect.

Renewable Energy Credit Revenues

Q. HAS RMP PROVIDED ANY UPDATES TO THE PROJECTED RENEWABLE ENERGY CREDIT ("REC") SALES REVENUES INCORPORATED IN ITS FILING?

A. Yes. The test year REC sales revenues are based on a combination of actual known sales that have already been committed to for the test year and projected additional sales. Since the volume of sales, and the price received for the RECs can vary significantly, the REC sales revenues are ultimately trued-up through the REC balancing account. Even with the REC balancing account ("RBA") in place, it is still preferable to include as accurate of a forecast as possible in the test year as carrying charges are applied to the RBA balance. In this case, UAE Data Request 2.2 asked the Company to update all entries in its REC revenue adjustment with the most recent information and data available and to provide additional updates when new information becomes available. In the 1st Supplemental response to UAE Data Request 2.2, dated March 24, 2014, RMP provided an update to the REC revenue adjustment contained in its filing. The update included additional known test year sales that were not included in the original filing and some revisions to the projected sales prices for additional estimated test year sales. In the update, the Leaning Juniper revenues remain unchanged from the amount in the filing.

Q. AT THIS TIME, DO YOU RECOMMEND THAT THE UPDATED REC REVENUE PROJECTIONS PROVIDED IN THE 1ST SUPPLEMENTAL RESPONSE TO UAE DATA REQUEST 2.2 BE REFLECTED IN THIS CASE?

A. Yes. This update would reflect the impact of some additional now known test year REC sales, as well as RMP's more recent projections of test year sales prices for yet uncommitted sales.

Q. ARE YOU RECOMMENDING ANY ADDITIONAL REVISIONS TO THE REC REVENUES INCORPORATED IN THE FILING?

A. Yes. Under Paragraph 39 of the 2012 Stipulation in RMP's prior general rate case, Docket No. 11-035-200, RMP is permitted to retain ten percent (10%) of revenues it obtains from sales of its RECs for contracts entered into after July 1, 2012 as an incentive to aggressively market RECs and obtain additional value for its RECs. All of the RECs incorporated in the test year are associated with contracts entered into after July 1, 2012 and would qualify for the 10% RMP incentive. Thus, I recommend that the updated REC sales revenues be reduced by 10% so that the 10% incentive would be retained by RMP.

Q. COULD YOU EXPLAIN WHY YOU RECOMMEND THE 10% INCENTIVE BE REMOVED FROM THE REC REVENUES PROJECTED IN THIS CASE INSTEAD OF JUST BEING FULLY REFLECTED IN A FUTURE REC BALANCING ACCOUNT REVIEW?

A. Amounts that are trued-up in the RBA are subject to carrying charges. In response to OCS Data Request 13.7, the Company indicated that it does intend to apply carrying charges on the ten percent incentive in the RBA balancing account. However, with regards to the ten percent incentive, the response also indicated that the Company "… would be amenable to including an estimate in the general rate case to be trued up in the RBA if parties prefer that treatment."

Q. WHAT ADJUSTMENT IS NEEDED TO REFLECT THE UPDATED REC REVENUE ESTIMATES PROVIDED BY RMP AND TO REMOVE THE TEN PERCENT THAT RMP IS PERMITTED TO RETAIN AS AN INCENTIVE?

A. As shown on Exhibit OCS 3.13D, test year REC revenues should be increased by $180,442 on a Utah basis. This would result in total test year REC revenues (excluding the Leaning Juniper revenue) of $2,449,852 on a Utah basis, reduced by $244,985 to reflect RMP's incentive share, for a net amount of $2,204,867.

Legal Expense

Q. WHAT AMOUNT OF LEGAL EXPENSE IS INCLUDED IN THE BASE YEAR AND IN THE TEST YEAR?

A. In response to OCS Data Request 4.17, Confidential Attachment OCS 4.17, the Company provided an itemized listing of all outside legal expenses included in the base year and in the test year by legal matter. The response identifies the total base year legal expense recorded on the Company's books as ****BEGIN CONFIDENTIAL**** [redacted] ****END CONFIDENTIAL****

Q. ARE THERE ANY COSTS FOR LEGAL MATTERS RECORDED DURING THE BASE YEAR THAT YOU RECOMMEND BE REMOVED FROM THE ESCALATED TEST YEAR EXPENSES?

A. Yes. During the base year, the Company incurred costs associated with the dispute between PacifiCorp and USA Power, LLC. According to the response to DPU Data Request 21.3, the USA Power judgment has been recorded below-the-line on PacifiCorp's books with a nonutility allocation so that the judgment is not included in the Company's filing. However, the legal costs incurred by RMP associated with the USA Power, LLC dispute remain in the base year and in the test year costs that are allocated to the Utah jurisdiction. I recommend these costs be removed from the test year and not charged to RMP's ratepayers in the state of Utah.

Q. WOULD YOU PLEASE DESCRIBE THE DISPUTE BETWEEN PACIFICORP AND USA POWER, LLC AND THE STATUS OF THE DISPUTE?

A. Rather than independently summarizing the dispute and the status of the dispute, the below quotation is taken directly from PacifiCorp's 2013 Annual Report (Form 10-K) filed with the Securities and Exchange Commission, specifically contained within Note 13 to the financial statements.

> *USA Power*
>
> In October 2005, prior to MEHC's ownership of PacifiCorp, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in the Third District Court of Salt Lake County, Utah ("Third District Court") by USA Power, LLC, USA Power Partners, LLC and Spring Canyon Energy, LLC (collectively, the "Plaintiff"). The Plaintiff's complaint alleged that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accused PacifiCorp of breach of contract and related claims in regard to the Plaintiff's 2002 and 2003 proposals to build a natural gas-fueled generating facility in Juab County, Utah. In October 2007, the Third District Court granted PacifiCorp's motion for summary judgment on all counts and dismissed the Plaintiff's claims in their entirety. In February 2008, the Plaintiff filed a petition requesting consideration by the Utah Supreme Court. In May 2010, the Utah Supreme Court reversed summary judgment and remanded the case back to the Third District Court for further consideration, which led to a trial that began in April 2012. In May 2012, the jury reached a verdict in favor of the Plaintiff on its claims. The jury awarded damages to the Plaintiff for breach of contract and misappropriation of a trade secret in the amounts of $18 million for actual damages and $113 million for unjust enrichment. In May 2012, the Plaintiff filed a motion seeking exemplary damages. Under the Utah Uniform Trade Secrets law, the judge may award exemplary damages in an additional amount not to exceed twice the original award. The

Plaintiff also filed a motion to seek recovery of attorneys' fees in an amount equal to 40% of all amounts ultimately awarded in the case. In October 2012, PacifiCorp filed posttrial motions for a judgment notwithstanding the verdict and a new trial (collectively, "PacifiCorp's post-trial motions"). The trial judge stayed briefing on the Plaintiff's motions, pending resolution of PacifiCorp's post-trial motions. As a result of a hearing in December 2012, the trial judge denied PacifiCorp's post-trial motions with the exception of reducing the aggregate amount of damages to $113 million. In January 2013, the Plaintiff filed a motion for rejudgment interest. In the first quarter of 2013, PacifiCorp filed its responses to the Plaintiff's post-trial motions for exemplary damages, attorneys' fees and prejudgment interest. An initial judgment was entered in April 2013 in which the trial judge denied the Plaintiff's motions for exemplary damages and prejudgment interest and ruled that PacifiCorp must pay the Plaintiff's attorneys' fees based on applying a reasonable rate to hours worked rather than the Plaintiff's request for an amount equal to 40% of all amounts ultimately awarded. In May 2013, a final judgment was entered against PacifiCorp in the amount of $115 million, which includes the $113 million of aggregate damages previously awarded and amounts awarded for the Plaintiff's attorneys' fees. The final judgment also ordered that postjudgment interest accrue beginning as of the date of the April 2013 initial judgment. In May 2013, PacifiCorp posted a surety bond issued by a subsidiary of Berkshire Hathaway to secure its estimated obligation. PacifiCorp strongly disagrees with the jury's verdict and plans to vigorously pursue all appellate measures. Both PacifiCorp and the Plaintiff filed appeals with the Utah Supreme Court. The parties are briefing their positions before the Utah Supreme Court with briefing expected to be completed and oral arguments held by late 2014. As of December 31, 2013, PacifiCorp had accrued $117 million for the final judgment and postjudgment interest, and believes the likelihood of any additional material loss is remote; however, any additional awards against PacifiCorp could also have a material effect on the consolidated financial results. Any payment of damages will be at the end of the appeals process, which could take as long as several years.

Q. WHAT ADJUSTMENT IS NEEDED TO REMOVE THE LEGAL COSTS FOR THE USA POWER MATTER?

A. As shown on Confidential Exhibit OCS 3.14D, test year expenses should be reduced by ****BEGIN CONFIDENTIAL**** [redacted] ****END CONFIDENTIAL****

<u>CWIP Write-Offs</u>

Q. HOW MUCH DID THE COMPANY CHARGE TO EXPENSE DURING THE TEST YEAR FOR PROJECTS THAT WERE PREVIOUSLY RECORDED IN CONSTRUCTION WORK IN PROGRESS ("CWIP") ON ITS BOOKS?

A. In Filing Requirement R746-700-22-D.2, the Company indicates that base year expenses recorded in various FERC expense accounts include $8,051,056 ($3,473,427 Utah basis) for the write-off of costs that were previously included in CWIP on its books. These amounts were escalated in the Company's filing in determining the test year expense.

Q. OF THE $8,051,056 OF PROJECT COSTS THE COMPANY WROTE-OFF TO EXPENSE IN THE BASE YEAR, ARE THERE ANY THAT YOU RECOMMEND BE REMOVED FROM TEST YEAR EXPENSE?

A. Yes, I recommend that two specific items be removed from test year expense. These include the charge to expense to establish a reserve in anticipation of a possible write-off for the "Wallula McNary 230kV Line" project and the write-off of unused electronic equipment associated with cancelled electronic security projects that were being done to comply with NERC/Critical Infrastructure Protection Standards.

Q. PLEASE DISCUSS THE WALLULA MCNARY 230KV LINE PROJECT AND THE REASON WHY YOU RECOMMEND THE ASSOCIATED EXPENSE BE REMOVED FROM THE TEST YEAR?

A. In September 2012, RMP charged $1,700,000 to FERC Account 573 – Maintenance of Miscellaneous Transmission Plant Expense for this project. The response to OCS Data Request 3.1 indicates that the costs include internal and external contracted costs associated with transmission line permitting efforts "…including public outreach, line design, planning engineering associated with the Western Electricity Coordinating Counsel line rating process, coordination with the Bonneville Power Administration associated with the interconnection of the proposed line with their facility, and overhead costs applied to the project." The response also indicates that the costs have not been written-off on PacifiCorp's books, but rather a "…reserve has been taken in anticipation of a possible write off." The driver of the establishment of the reserve is the possible mutual termination of transmission service agreements that supported the need for the Wallula McNary 230Kv line project.

In response to OCS Data Request 19.1, the Company indicated that it agreed to terms with one customer that requested termination of their service agreement, but that a second customer has determined a need to maintain the service agreement. The Company is currently analyzing whether there is an option of serving the second customer's transmission service request without building the new line. The response indicates that "At this time no decisions have been made if there are options to building the new line" and that "If the line is built the $1.7 million will be put into service." Thus, the $1.7 million that was charged to expense during the base year in establishing a reserve for possible write-off of the line may be reversed at a future time if the line is built. After application of the escalation factor used in the filing for FERC account 573, the test year expense is $1,739,100.

If the $1.7 million, plus escalation, remains in expense in the test year and PacifiCorp moves forward with the transmission line, it will recover the costs in expense and will include the cost in plant in service in a future proceeding resulting in a double-recovery of the costs. Given the uncertainty, I recommend that the amount charged to expense to establish the reserve be removed from test year expense in this case.

Q. PLEASE DISCUSS THE WRITE-OFF OF THE UNUSED ELECTRONIC EQUIPMENT THAT OCCURRED DURING THE BASE YEAR.

A. During the base year, the Company wrote-off $1,967,630 to expense for a project identified as "Generation Compliance Initiative Hardware." The response to OCS Data Request 3.2 indicates that the "computer equipment and configuration expenses" that were written-off were directly associated with the abandoned electronic security projects that were initiated to comply with the NERC CIP standards. The software costs and some of the configuration expenditures were written-off in the test year in the last rate case, the hardware and additional configuration expenditures were subsequently written-off in the test year in this rate case. At the time of the prior rate case, the Company was attempting to redeploy the hardware equipment throughout the PacifiCorp divisions and therefore it was not written off at that time. The base year write-off in this case of $1,967,630 is for the equipment that the Company was unable to deploy and use in its system.

Q. DID YOU ADDRESS THE WRITE-OFF OF THE SOFTWARE AND CONFIGURATION EXPENDITURES IN THE PRIOR RATE CASE, DOCKET NO. 11-035-200?

A. Yes. In my direct testimony in that docket, I recommended that the costs that were written-off be removed from the test year expenses. The costs were for an electronic security project to meet NERC CIPS standards that was cancelled by PacifiCorp. As indicated in my direct testimony in the last rate case, in February 2010, PacifiCorp Energy management and the PacifiCorp information technology department performed an internal reassessment of the project after it had already begun and determined the project should be replaced with a different project supported by internal resources instead of an outside vendor. The replacement project was done in-house by the Company. If the Company had done a more robust evaluation and assessment before the project had begun, the considerable costs that had been incurred and ultimately written-off by the

Company could have been avoided. Since the last rate case resulted in a settlement, the cancellation of the project and the associated write-off of the project cost were not addressed by the Commission.

Q. WHAT ADJUSTMENT IS NEEDED TO REMOVE THE EXPENSE ASSOCIATED WITH THE IMPAIRED AND UNUSED EQUIPMENT FROM THE TEST YEAR?

A. After application of the 5.24% escalation factor applied by RMP to the base year expense of $1,967,630, test year expenses should be reduced by $2,070,734 to remove the "Generation Compliance Initiative Hardware" costs that were written-off.

Q. WHAT IS THE IMPACT OF YOUR TWO RECOMMENDED CWIP WRITE-OFF ADJUSTMENTS DISCUSSED ABOVE?

A. As shown on Exhibit OCS 3.15D, test year expenses should be reduced by $3,809,834 on a total Company basis and $1,624,068 on a Utah jurisdictional basis.

<u>RATE BASE ADJUSTMENTS</u>

<u>Double-Count of Overhaul Project Capital Costs</u>

Q. WHAT IS THE PURPOSE OF THE ADJUSTMENT SHOWN ON EXHIBIT OCS 3.16D?

A. As part of its Miscellaneous Rate Base Adjustment on Exhibit RMP__(SRM-3), at page 8.7.1, the Company includes overhaul prepayments in rate base. These are pre-paid amounts associated with overhaul costs that are ultimately capitalized as plant in service when the overhaul is completed. Included in the Miscellaneous Rate Base Adjustment are the projected average test year prepayments for the Lake Side U11 and U12 combustion overhaul. The capital costs associated with the same Lake Side U11 and U12 combustion overhaul is included in plant in service on Exhibit RMP__(SRM-3), at page 8.6.23, with an in-service date shown as March 2015. In reviewing the details of each of the adjustments, it was discovered that there was a two month overlap during which the capital costs were included in both the prepayments and in plant in service.

In response to OCS Data Request 19.11, the Company agreed that the capital costs associated with the Lake Side U11 and U12 Combustion Overhaul projects should reflect an in-service date of May 2015 instead of March 2015. RMP indicated in the response that it will make the correction to the capital database in its rebuttal filing. As shown on Exhibit OCS 3.16D, plant in service should be reduced by $5,037,792 on a total Company basis and $2,147,510 on a Utah basis to remove the impacts of the two month overlap and to reflect the corrected in-service date for the project. As shown on the exhibit, using the current depreciation rate for other production plant of 2.939%, depreciation expense and accumulated depreciation should each be reduced by $148,061 on a total Company basis and $63,115 on a Utah basis.

<u>Remove Unsupported Condemnation Settlements</u>

Q. EXHIBIT OCS 3.17D IS TITLED "REMOVE CONDEMNATION SETTLEMENTS." WHAT DOES THIS EXHIBIT ADDRESS?

A. On Exhibit RMP__(SRM-3), at page 8.6.24, RMP added $8,202,044 to transmission plant in service for a project described as "Populus – Terminal 345 kV line – condemnation settlements", with a projected in-service date of February 2014. At page 8.6.37 of the same RMP exhibit, the project is described as follows:

> This project is part of the close out activities on the Populus-Terminal 345 kV line project which constructed a 135 mile double circuit 345kV line originating from Populus substation near Downey, Idaho and ending at Terminal substation near Salt Lake City, Utah. There were a number of condemnation complaints filed during this project that were resolved and there are two remaining condemnation actions that are both related to the impact of the transmission line on open pit mining activities.

I recommend that the project be removed from the test year in this case.

Q. WHY DO YOU RECOMMEND THAT THE PROJECT BE REMOVED FROM THE TEST YEAR?

A. In a DPU follow-up request to its original Data Request 6.6, dated March 18, 2014, RMP was asked to "Provide additional support for the amount of the Populus-Terminal condemnation settlements." The response indicated that the information requested "…is highly confidential and available for review at the Company's offices." The "highly confidential" response was reviewed by the OCS. The very limited information provided by RMP for review by the OCS did not provide a reasonable level of support or details justifying the inclusion of the $8.2 million in plant in service in this case. To the best of my knowledge, RMP has not provided any additional support for the $8.2 million beyond the paragraph referenced above and the very limited information made available for review at its offices. It is RMP's responsibility to demonstrate that the projected costs it is including in the test year are reasonably calculated and appropriate for inclusion in rates. Thus far, RMP has failed to support the inclusion of the $8.2 million in this case.

Q. ARE THERE ADDITIONAL REASONS THAT THESE COSTS SHOULD BE REMOVED FROM THE TEST YEAR?

A. Yes. In response to DPU 35.1, Attachment DPU 35.1-1, the Company indicated that it no longer projects this project will be added to plant in service during the test year. Specifically, the response states: "In-service date has been extended to November 2015 due to the expected date of the outstanding condemnation cases." Since the costs now fall outside of the test year, they should be removed.

Q. WHAT ADJUSTMENT IS NEEDED TO REMOVE THE "POPULUS-TERMINAL 345KV LINE – CONDEMNATION SETTLEMENTS" FROM THE TEST YEAR?

A. As shown on Exhibit OCS 3.17D, plant in service should be reduced by $8,202,044 ($3,496,367 Utah), depreciation expense should be reduced by $142,798 ($60,872 Utah) and accumulated depreciation should be reduced by $118,998 ($50,726 Utah).

<u>Net Pension and Post-Retirement Welfare Plan Prepaid Asset</u>

Q. ARE THERE ANY SIGNIFICANT BALANCE SHEET ITEMS THAT RMP IS REQUESTING TO INCLUDE IN RATE BASE FOR THE FIRST TIME IN THIS RATE CASE?

A. Yes. RMP witness Douglas K. Stuver addresses the Company's request to include PacifiCorp's prepaid pension asset and accrued other post-retirement benefit liability, net of accumulated deferred income taxes, in rate base. This request results in: 1) $312.2 million being added to rate base for the prepaid pension balances; 2) $31.2 million being deducted from rate base for the other post-retirement plan liability; and 3) $119.0 million being deducted from rate base for the associated accumulated deferred income tax liabilities. The net result is a $162.0 million ($68.8 million Utah) increase in rate base. This is the first case in which the Company has included the prepaid pension balance and the accrued other post-retirement welfare plan liability in rate base.

Q. WHAT IMPACT DOES THE INCLUSION OF THESE ITEMS HAVE ON THE REVENUE REQUIREMENTS?

A. At the rate of return requested by RMP in this case, the inclusion of the net $162.0 million ($68.6 million Utah) in rate base increases Utah revenue requirements by $7,493,864.[5] This adjustment accounts for

[5] Amount calculated by turning off (or disabling) the adjustment in the Jurisdictional Allocation Model used by RMP in determining the Utah revenue requirements.

almost 10% of the $76,252,101 increase in rates requested by RMP in this case.

Q. WHAT IS THE PREPAID PENSION ASSET AND THE OTHER POST-RETIREMENT LIABILITY?

A. As explained at page 2 of Mr. Stuver's direct testimony, the prepaid pension asset that exists on PacifiCorp's books "…represents the cumulative contributions made to the Company's pension plan in excess of cumulative expense." Similarly, the existing accrued other post-retirement liability "…represents the cumulative expense recognized in excess of cumulative contributions." In other words, the balance in the prepaid asset or the accrued liability each year is based on a running tally of the total amount of cash contributions made to the pension plan and the other post-retirement benefit ("OPEB") plan less the total amount of expense recorded on PacifiCorp's books over time.

Q. WILL THERE ALWAYS BE A PREPAID PENSION ASSET AND AN OTHER POST-RETIREMENT LIABILITY ON PACIFICORP'S BOOKS?

A. No. Over time, the total amount of cash contributions to the pension plan and the other post-retirement benefit plan should equal the total amount of expense associated with the plans. In other words, over the long-term, the total amount of cash contributions less the total amount expensed on the books should equal $0. The total cumulative difference between the cash contributions made into the plans and total amount of expense recorded on the books will change from year to year, but over the long term they should ultimately equal.

Q. HAS THE CUMULATIVE DIFFERENCE BETWEEN THE TOTAL CASH CONTRIBUTIONS TO THE PENSION PLAN AND THE TOTAL PENSION EXPENSE ALWAYS RESULTED IN A PREPAID PENSION ASSET?

A. No, it has not. In fact, from at least 1997 through the fiscal year ended March 2006, an accrued pension liability existed on PacifiCorp's books. In other words, from at least 1997 through March 2006, the total amount of pension expense booked by PacifiCorp exceeded the cash contributions to the pension plan.

Exhibit OCS 3.18D, page 3.18.1 presents the accrued pension liability balance as of 1997, the annual cash contributions to the pension plan for 1998 through June 2013, the annual actuarially determined pension expense for 1998 through June 2013, and the resulting year end prepaid/(accrued) pension balance for each year, 1997 through June 2013.[6] This clearly demonstrates that an accrued pension liability existed for PacifiCorp from 1996 through March 2006. The same information is also provided for the other post-retirement benefit plan. As shown on the

[6] Amounts provided in response to OCS Data Request 9.6, Attachment OCS 9.6.

exhibit, the other post-retirement benefit plan has consistently had an accrued liability balance since at least 1998.

Q. DID THE COMPANY ALSO HAVE ACCRUED LIABILITIES FOR THE PENSION AND OTHER POST-RETIREMENT BENEFIT PLANS PRIOR TO 1997?

A. Yes. In response to OCS Data Request 9.6 the Company indicated that "Information prior to 1998 is not readily available." However, the response to DPU Data Request 39.12, attachment DPU 39.12 shows that there were accrued liabilities for the other post-retirement benefit plan going back to 1993. Thus, there was an accrued liability balance from at least 1993 through 2006, a period of thirteen years.

Q. DURING THE PERIOD IN WHICH THERE WAS AN ACCRUED PENSION LIABILITY ON PACIFICORP'S BOOKS, DID THE COMPANY REFLECT THE LIABILITY AS A REDUCTION TO RATE BASE?

A. No, it did not. As previously mentioned, this is the first case in which the Company is proposing to include the prepaid pension asset in rate base. In the historical periods in which there was an accrued pension liability on PacifiCorp's books, the balance was not included as a rate base item. OCS Data Request 18.8 asked the Company to explain, in detail, why it did not propose to decrease rate base for the net liability balance during the period there was an accrued pension liability. In response, the Company indicated in part: "The concept of financing costs on the prepaid pension asset or accrued pension liability resulting from differences in cumulative pension contributions and expense not be included in revenue requirement was not identified by the Company until recently." Apparently this recent revelation by PacifiCorp, which occurred during a period that a net prepaid asset exists, has prompted the significant increase in rate base requested for the first time in this case.

Q. WHAT REASON DOES THE COMPANY PROVIDE FOR INCLUDING THE NET PREPAID BALANCE IN RATE BASE AT THIS TIME?

A. At page 3 of his testimony, Mr. Stuver contends that the Company has recovered pension and other post-retirement costs based on the amount recorded to expense and that using this approach, "…investor capital is required to finance any difference between the amounts *contributed* and the amounts *expensed*." (emphasis supplied). He contends that investors should be compensated for their cost of capital for financing the contributions that are in excess of the expenses. He also agrees that it would be appropriate to reduce rate base by the customer-provided funds if the expenses exceed the cash contributions to the plans.

At page 7 of his testimony, Mr. Stuver explains that the net prepaid pension asset has grown significantly since 2006 for various reasons and that the Company expects the amount to continue to grow. Now that it has grown to a large net prepaid asset, the Company is seeking to include the balance in rate base to earn a return.

Q. DO YOU AGREE THAT THE PREPAID PENSION BALANCE AND THE ACCRUED OTHER POST-RETIREMENT BENEFIT LIABILITY SHOULD BE INCLUDED IN RATE BASE?

A. No. Rather than separately addressing the pension and other post-retirement benefit plan balances, I will hereafter refer to them as the "net prepaid asset" or the "net accrued liability" for ease of discussion. I recommend that the net prepaid balance be excluded from rate base for the many reasons that I will address in this testimony.

Q. WHAT IS YOUR FIRST REASON FOR RECOMMENDING THAT THE NET PREPAID ASSET BE EXCLUDED FROM RATE BASE?

A. As shown on Exhibit OCS 3.18D, page 3.18.1, from at least 1997 through 2006 PacifiCorp had a net accrued liability. During that time, rate base was not reduced. It would be unfair to charge ratepayers a return now that PacifiCorp is in a net prepaid asset position when ratepayers did not benefit during the long period of net accrued liability.

Q. HAS PACIFICORP DEMONSTRATED THAT THE NET PREPAID BALANCE THAT IT PROJECTS FOR THE TEST YEAR IN THIS CASE WAS FUNDED BY SHAREHOLDERS?

A. No, it has not. The average test year net prepaid balance added to rate base by PacifiCorp is based on the total difference between the amount of cash contributions and the actuarially determined amounts charged to expense on its books over many, many years going back as far as at least the early 1990s and possibly earlier. It is the cumulative difference between the cash funding and the actuarially determined expense that PacifiCorp contends has been funded by shareholders. In order for PacifiCorp's contention that the cumulative difference, or the net prepaid asset, has been funded by shareholders to be accurate, at a minimum, the amount of actuarially determined expense in each and every year would have to equal the amount collected in rates. This is not the case.

Q. WHY NOT?

A. The amount of pension expense and other postretirement benefit expense factored into the rates charged to customers differs from the actual amount booked by the Company in any given year. This is true for many reasons. For example, rates are not reset annually and the amount of expense booked by the Company changes annually based on the actuarial projections. Additionally, during some of the past years that led to the cumulative difference between the cash funding and expense, rates were set based on historic test years. During more recent periods, rates were set based on forecast periods. Thus, actual amounts recorded by PacifiCorp on its books for the actuarially determined pension and other post-retirement benefit expense are different from the amount that is used in establishing the rates charged to customers. The differences are not trued-up for ratemaking purposes in Utah.

Q. ARE THERE ADDITIONAL REASONS THAT THE AMOUNTS CONSIDERED IN RATES CHARGED TO CUSTOMERS DIFFER FROM

THE PER-BOOK EXPENSE AMOUNTS THAT ARE FACTORED INTO THE DETERMINATION OF THE NET PREPAID ASSET?

A. Yes. As previously indicated in this testimony, the amount of pension expense and other post-retirement benefit expense included in the revenue requirement calculations exclude the amounts that are charged to joint ventures. It also excludes the amounts applicable to mining operations, as the rates are being established for the electric operations. Based on a review of the amounts provided by the Company, it appears that the mining operations and the amounts that are applicable to joint ventures are included in the amount of pension expense that is booked by PacifiCorp and factored into the determination of the net prepaid asset amount.

Q. DO YOU HAVE ANY EXAMPLES THAT DEMONSTRATE THAT THE ACTUARIALLY DETERMINED EXPENSES CONSIDERED IN THE DETERMINATION OF THE NET PREPAID ASSET INCLUDES PENSION EXPENSE ASSOCIATED WITH MINING OPERATIONS AND JOINT VENTURE AMOUNTS?

A. Yes. In response to OCS Data Request 9.5, Attachment OCS 9.5-1 shows that the calculation of the net prepaid asset includes $14.8 million for the 2014 pension expense. As indicated previously in this testimony, the $14.8 million was the total actuarially projected pension expense for PacifiCorp at the time it prepared its filing. In determining the test year expense in this case, RMP removed the portion of the $14.8 million applicable to the mining operations and applicable to joint ventures.

The response also shows that the calculation of the net prepaid asset includes $6.6 million for the actuarially determined other post-retirement benefit expense. As indicated previously in this testimony, the Company is projecting a negative expense (i.e., income amount) for the other post-retirement benefit plan electric operations during 2014. The only reason the actuarially determined amount is an expense of $6.6 million is due to the inclusion of $8,024,000 associated with the mining operations which are not included in the expense that is factored into the revenue requirements. The amount applicable to the electric operations is ($1,401,000).

Q. WOULD A PORTION OF THE CASH CONTRIBUTIONS TO THE PENSION PLAN AND THE OTHER POST-RETIREMENT BENEFIT PLAN ALSO BE ATTRIBUTABLE TO THE MINING OPERATIONS AND THE PORTION OF COSTS CHARGED TO JOINT VENTURES?

A. Yes, presumably so.

Q. DOES THE COMPANY RECEIVE RATE BASE RECOVERY OF ANY OF THE PENSION AND OTHER POST-RETIREMENT BENEFIT EXPENSE AMOUNTS?

A. Yes. Each year a portion of the actuarially determined pension expense and other post-retirement benefit expense is capitalized as part of the capital projects that are ultimately placed into plant in service. Additionally, a portion is charged to non-utility operations. The benefit costs follow the labor costs such that a portion of the benefit costs incurred by PacifiCorp are capitalized along with the labor costs and a portion are charged to non-utility along with labor costs. This is demonstrated in Exhibit RMP__(SRM-3), page 4.2.2. In this case, approximately 29% of all labor costs are charged to capital and non-utility. Thus, a portion of the actuarially determined pension expense and other post-retirement benefit expense has been capitalized and is included in rate base as plant in service. The Company is earning a return on the balances that have been added to plant in service.

Q. THE NET PREPAID BALANCE IS BASED IN PART ON THE AMOUNT OF CASH CONTRIBUTIONS MADE BY PACIFICORP TO THE PLANS. DOES THE COMPANY HAVE ANY DISCRETION WITH REGARDS TO THE AMOUNT OF CASH CONTRIBUTED TO THE PLAN IN ANY GIVEN YEAR?

A. Yes. There is a great deal of discretion with regards to the annual pension contributions made by PacifiCorp with a huge range between the minimum required funding level and the maximum tax deductible funding level. For example, the response to OCS Data Request 4.9, Attachment OCS 4.9 indicates that the minimum required contribution to the pension plan for 2012 was $0 and the Company contributed $59.2 million in that year. For 2012, the response shows that the actuarially determined pension expense was $24.4 million. Thus, during 2012 the Company contributed significantly more than the minimum required funding and considerably more than the actuarially determined pension expense. At least a portion of the net prepaid asset balance is the result of discretionary contributions. While larger contributions will reduce the pension expense over time, they also increase the net prepaid pension balance that PacifiCorp is seeking to include in rate base in this case.

Q. WHAT ADJUSTMENT SHOULD BE MADE TO REMOVE THE NET PREPAID ASSET FROM RATE BASE IN THIS CASE?

A. The adjustment shown on Exhibit RMP__(SRM-3), at page 8.14 should be reversed. This is shown on Exhibit OCS 3.18D, which removes both the net prepaid balance of $280,974,096 ($119,330,500 Utah) and the offsetting Accumulated Deferred Tax Balance of $118,983,500 ($50,532,632 Utah) from rate base. This adjustment reduces the Company's requested revenue requirement by $7,035,000 at the OCS' recommended rate of return in this case and by $7,494,000 at the Company's requested rate of return.

Q. IF THE COMMISSION WERE TO DETERMINE THAT RATE BASE TREATMENT SHOULD BE CONSIDERED FOR THE CASH CONTRIBUTIONS MADE TO THE PENSION PLAN, DO YOU HAVE ANY APPROACHES FOR THE COMMISSION'S CONSIDERATION?

A. First and foremost, I recommend that the net prepaid asset not be given rate base recognition in this case or in future Utah rate cases. However, if the Commission finds some merit to the Company's contention that shareholders are funding contributions to the pension plan which exceed the amount of pension expense collected from ratepayers, then I recommend that the potential rate base addition be considered on a prospective basis only. Starting with the test year in this case, one could consider the difference between the amount of cash funding into the pension plan that is applicable to electric operation employees (in other words exclusive of mining operations) and the amount of pension expense that is factored into the revenue requirements that are collected from customers. The amount of cash funding and the amount of expenses factored into the revenue requirement as a result of general rate cases could be tracked going forward and only the cumulative difference between these two amounts applicable to the Utah jurisdiction should be considered for rate base treatment. This would ensure that the calculation is in fact only based on the electric operations, only based on the Utah jurisdictional amounts, and based on the amount actually being recovered in rates charged to Utah customers. While I do not recommend this approach, it is far more reasonable than the approach proposed by PacifiCorp in this case which is based on many, many years of past accounting entries that differ from the amounts included in electric rates charged to Utah customers.

ENERGY IMBALANCE MARKET COSTS

Q. WHAT IS THE ENERGY IMBALANCE MARKET?

A. Beginning at page 30 of his testimony, Gregory N. Duvall describes the Energy Imbalance Market ("EIM") as "…a balancing market that optimizes generator dispatch every five minutes within and between the PacifiCorp and CAISO balancing authority areas…" He contends that the EIM will allow for "…more reliable and lower cost operation than is possible with the bilateral hourly market transactions currently available to the Company." PacifiCorp anticipates that participation in the EIM will produce benefits to customers in the form of reduced net power costs. Mr. Duvall's testimony indicates that commercial operation and participation in the EIM is currently planned for October 2014, which falls within the test year in this case.

Q. WERE THE PROJECTED EIM COSTS AND PROJECTED POWER COST REDUCTIONS INCLUDED IN THE TEST YEAR REVENUE REQUIREMENTS?

A. No. Mr. Duvall indicates at pages 30 and 31 of his direct testimony that the projected benefits and costs associated with PacifiCorp's participation in the EIM are highly uncertain largely because the EIM market design is still ongoing. He indicates that due to the uncertainty regarding both the benefits and the costs of PacifiCorp's participation in the EIM, the impact of the EIM was not included in the revenue requirements in this case.

Q. WHAT COSTS HAS THE COMPANY IDENTIFIED ASSOCIATED WITH ITS PARTICIPATION IN THE EIM?

A. At page 31, lines 645 – 651 of his testimony, Mr. Duvall identifies the following costs associated with PacifiCorp's participation in the EIM:

- One-time charge for the CAISO to expand its network model. The response to OCS Data Request 9.20 identifies this one-time charge as \$2.1 million; however, it is my understanding that these fees have recently been increased by \$462,800 under an amendment to the EIM implementation agreement. The response also indicates that this one-time charge will be will be capitalized to plant in service.
- Capital Costs. The response to OCS Data Request 9.20 describes the capital costs as primarily related to "upgrading real-time and settlement metering and telecommunications equipment", systems and support. The response also indicates that as of July 2013, these capital costs were projected to be \$13.7 million, exclusive of the one-time charge addressed above.
- Ongoing O&M Expense for variable fees paid to CAISO. These consist of new administrative fees based on actual transactions executed and additional market charges incurred when doing business with CAISO. The response to OCS Data Request 9.20 indicates that as of July 2013, the ongoing variable fees to be paid to CAISO were projected to be \$1.4 million annually.

– Ongoing O&M related to additional headcount, IT systems and support. The response to OCS Data Request 9.20 indicates that the projected annual expenses related to additional headcount, IT systems and support was $1.6 million as of July 2013, with a projected increase in full time equivalent employees of 8.

Q. HAVE THE PROJECTED POWER COST SAVINGS RESULTING FROM PACIFICORP'S PARTICIPATION IN THE EIM BEEN PROVIDED IN THIS CASE?

A. The projected amount of savings was not provided in the EIM section of Mr. Duvall's testimony. In a March 13, 2013 report referenced in Mr. Duvall's testimony, Energy and Environmental Economics, Inc. projected annual benefits from participation in the EIM of $21 million to $129 million in 2017 for both CAISO and PacifiCorp combined, with the estimated annual benefits to PacifiCorp ranging from $10.5 million to $54.4 million in 2017. The report used a 2017 study year and did not provide estimated cost savings for the test year or any years prior to 2017. The response to OCS Data Request 2.31 indicates that no additional benefit analysis has been done since the March 13, 2013 report, and that the range of expected benefits is dependent on "...yet uncertain factors of final market design which is still subject to Federal Energy Regulatory Commission (FERC) approval and testing and simulations that could result in changes to how and when the market will begin." Thus, it is unclear what savings may transpire during the test year based on the information provided by

PacifiCorp in this case and the report referenced by Mr. Duvall. In fact, it is not even clear if net savings will result during the test year. PacifiCorp has not indicated that it projects the reduction in test year power costs associated with its participation in the EIM will exceed the test year O&M costs.

Q. SINCE NO PROJECTED POWER COST SAVINGS HAVE BEEN REFLECTED IN THE NET POWER COSTS IN THIS CASE AND AN ESTIMATE OF THE POWER COST SAVINGS THAT MAY TRANSPIRE DURING THE TEST YEAR HAS NOT BEEN ESTIMATED BY PACIFICORP, HOW WOULD CUSTOMERS BENEFIT FROM THE SAVINGS SHOULD SAVINGS ACTUALLY TRANSPIRE DURING THE TEST YEAR AND SUBSEQUENT?

A. At page 32 of his testimony, Mr. Duvall indicates that the EIM benefits will automatically flow through the Energy Balancing Account (“EBA”) mechanism through lower net power costs. While not indicated in Mr. Duvall’s testimony, the EIM benefits would be subject to the 70%/30% sharing between ratepayers and PacifiCorp under the EBA mechanism. Therefore RMP would retain 30% of the power cost savings each year until the next base rate case since the projected savings have not been included in the estimated Net Power Costs in this case.

Q. WOULD THE PROJECTED COSTS FOR EIM PARTICIPATION ALSO FLOW THROUGH THE EBA?

A. Only the market charges paid to CAISO would be booked to the FERC accounts that are considered in the EBA mechanism. The CAISO administrative fees and internal O&M expenses would be booked in FERC expense accounts that fall outside of the accounts considered in the EBA. Additionally, the capital costs would not be included in the EBA as they would be booked to plant in service on the Company's books when placed into service.

Q. HAS THE COMPANY PROPOSED THAT THE COSTS ASSOCIATED WITH ITS PARTICIPATION IN THE EIM BE CONSIDERED IN THE EBA MECHANISM?

A. Yes. At pages 31 – 32 of his testimony, Mr. Duvall states: "The actual costs and benefits, including those costs not booked to NPC accounts, should be passed back to customers via the EBA, at least until such time as the costs and benefits are reflected in retail rates." Under his proposal to include the O&M expenses and capital costs not booked to Net Power Cost accounts in the EBA mechanism, the costs would also be subject to the EBA sharing band. He requests that the CAISO administrative costs permanently flow through the EBA mechanism and that the internal O&M costs and capital costs be included in the EBA mechanism until the costs are included in base rates in a future general rate case. He also indicates that if the Commission does not approve the EBA treatment described in his testimony, then "…the Company requests that non-NPC amounts be deferred as a regulatory asset in Account 182 for later inclusion in customer rates."

Q. DO YOU AGREE THAT THE EBA SHOULD BE MODIFIED TO ALLOW THE CAPITAL COSTS AND O&M EXPENSES ASSOCIATED WITH PACIFICORP'S PARTICIPATION IN THE EIM TO BE INCLUDED?

A. No, I do not. While the Company projects that it will incur capital costs and O&M expenses associated with its participation in the EIM during the test year in this case, I do not agree the associated costs, with the exception of the CAISO market charges, should be or need to be included in the EBA mechanism. In this case, PacifiCorp has not demonstrated that the power cost savings that will be or may be realized during the test year through its participation in the EIM will exceed the projected capital and O&M expenses it will incur during the test year. It is not clear that there will be a net benefit to customers in the first year of PacifiCorp's participation in the EIM. As indicated above, the only cost savings estimates that have been provided in this case thus far were based on a 2017 study year. They were not based on market conditions that are projected for the test year in this case. Under the Company's proposal, the costs would be flowed through to customers through the EBA even if PacifiCorp's participation in the EIM ends up being detrimental to customers and results in a net increase in costs.

Q. DO YOU AGREE WITH THE ALTERNATIVE PROPOSAL PRESENTED IN MR. DUVALL'S TESTIMONY?

A. Given the degree of uncertainty at this time with regards to the amount of costs that will be incurred by PacifiCorp during the test year associated with its participation in the EIM and the uncertainty regarding whether the net impact will be positive or negative during the test year and subsequent years (i.e., net costs or net savings), I agree that it would be reasonable to allow the Company to establish a regulatory asset to be considered in a future rate case proceeding. The regulatory asset should be effective the date rates established in this case go into effect and not retroactively applied prior to that date. In other words, RMP should not begin to defer the capital costs and the O&M expenses it incurs associated with its participation in the EIM until the rate effective date in this case. Any market charges while doing business with CAISO would fall under the EBA accounts when they begin to be incurred and should be excluded from the regulatory asset as they will be considered in the EBA mechanism.

Q. PART OF THE O&M EXPENSES PACIFICORP PROJECTS TO INCUR AS A RESULT OF ITS PARTICIPATION IN THE EIM IS FOR ADDITIONAL EMPLOYEES. SHOULD THE LABOR COSTS FOR THE ADDITIONAL EMPLOYEES TO BE RETAINED AS A RESULT OF THE EIM PARTICIPATION AUTOMATICALLY BE INCLUDED IN THE REGULATORY ASSET?

A. No, the additional labor costs should not automatically be included in the regulatory asset. As indicated previously in this testimony, PacifiCorp has steadily been reducing its FTE employee compliment. Previously in this testimony, I recommended that the test year labor costs be based on the actual FTE employee compliment as of January 31, 2014, which was 5,334.5 employees. The Company should not be permitted to defer any labor costs in the regulatory asset account unless its actual <u>net</u> employee compliment increases as a result of hiring the new employees. If the Commission accepts my recommended adjustment to reduce the test year labor costs to be based on an employee compliment of 5,334.5 FTEs, the labor cost associated with new employees hired as a result of the EIM participation should not be included in the regulatory asset unless PacifiCorp's actual total employee compliment exceeds 5,334.5 FTEs. If the Commission does not accept my recommended adjustment associated with the actual reduction in the employee compliment, the labor costs associated with new employees hired as a result of the EIM participation still should not be deferred unless the new employees cause the overall employee compliment to exceed the employee compliment that is factored into rates resulting from this case.

Q. WHEN AND OVER WHAT PERIOD SHOULD THE RESULTING REGULATORY ASSET BE RECOVERED FROM RATEPAYERS?

A. I recommend that the costs deferred in the regulatory asset begin to be recovered only after RMP is able to demonstrate that its participation in the EIM results in net benefits (i.e., net cost savings) to customers. At the time of the next rate case, if RMP is able to clearly demonstrate that its participation in the EIM results in net benefits to customers, recovery of the regulatory asset could begin with the rate effective date in that case. At the time of the next rate case, if RMP clearly demonstrates that its participation was cost effective, then interested parties such as the OCS can perform a detailed review of the costs deferred by the Company and address which of those costs are appropriate to be passed on to customers through amortization and what the appropriate amortization period would be.

Q. SINCE THE POWER COST REDUCTIONS RESULTING FROM PACIFICORP'S PARTICIPATION IN THE EIM HAVE NOT BEEN INCLUDED IN THE NET POWER COSTS IN THIS CASE AND WOULD FLOW THROUGH THE EBA SUBJECT TO THE 70%/30% SHARING MECHANISM, SHOULD A SHARING FACTOR ALSO BE APPLIED TO THE REGULATORY ASSET ACCOUNT?

A. Since RMP would get the full benefit of 30% of the actual power cost reductions resulting from its participation in the EIM due to the savings not being included in the Net Power Costs in this case, then it would be appropriate to record only 70% of the associated O&M expenses in the regulatory asset account. Application of the 70% factor to the regulatory asset account would match the portion of expenses being passed on to ratepayers with the portion of savings that would be passed on through the EBA.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE EIM.

A. The Company has not yet demonstrated that there is a net benefit to ratepayers resulting from its participation in the EIM, particularly for the test year ending June 30, 2015. I do not agree that it is appropriate to include the capital costs and O&M expenses associated with PacifiCorp's participation in the EIM in the EBA mechanism, with the exception of the CAISO market fees that fall within the FERC accounts considered in the EBA. I agree that it would be reasonable to allow PacifiCorp to defer the capital costs and O&M expenses associated with its EIM participation in a regulatory asset account beginning with the rate effective date in this case, but a 70% factor should be applied to match the sharing factor applied to the resulting net power costs savings that would flow through the EBA. Finally, labor costs associated with new employees hired as a result of PacifiCorp's participation in the EIM should not be included in the regulatory asset unless the resulting total employee compliment exceeds the employee compliment on which base rates in this case are set.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes.