Witness OCS – 3D

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations	)))))))	**Docket No. 10-035-124** **Direct Revenue Requirement Testimony of Donna Ramas For the Office of Consumer Services**

REDACTED

May 26, 2011

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INTRODUCTION

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

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

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

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

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

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

Q. ON WHOSE BEHALF ARE YOU APPEARING?

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

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

A. Yes. I have prepared Exhibits OCS 3.1 through 3.24, which are attached to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I present the overall revenue requirement recommended by the OCS and sponsor specific adjustments to the Company's filing for the future test period ending June 30, 2012. The overall revenue requirement presented in the summary schedules, specifically Exhibits OCS 3.1 and OCS 3.2, includes the impact of recommendations of other witnesses testifying on behalf of the OCS. It includes the recommended return on equity and capital structure presented by OCS witness Daniel Lawton, as well as specific adjustments recommended by OCS witnesses Michele Beck, Randall Falkenberg, and Seth Schwartz.

Q. PLEASE DISCUSS HOW YOUR EXHIBITS ARE ORGANIZED.

A. Exhibit OCS 3.1 presents the overall revenue requirement and summary schedules. Each of the pages in Exhibit OCS 3.1 is based on the Rolled-In allocation method. The direct testimony of OCS witness Michele Beck supports the use of the Rolled-In allocation method.

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

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

A. Exhibit OCS 3.2 includes a summary schedule that lists all of the OCS recommended adjustments in one schedule on a Utah basis. To be consistent with how RMP presented its case, the amounts presented on this schedule were calculated based on the revised protocol jurisdictional allocation method. The full revenue requirement impact will not tie directly into the summary schedule on Exhibit OCS 3.1 as the amounts on this schedule are based on the revised protocol method and 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.

The remaining exhibits attached to my testimony, Exhibits OCS 3.3 through 3.24, consist of the supporting calculations for the specific adjustments that I recommend the Commission adopt. These supporting exhibits are presented using the top-sheet approach, showing the specific adjustments on a total Company and Utah allocated basis with brief descriptions of the adjustments at the bottom of each exhibit.

In determining the Utah allocated impact of each adjustment in Exhibits OCS 3.2 through 3.24, the revised protocol jurisdictional allocations factors contained in Company Exhibit RMP__(SRM-3) are used, consistent with how RMP's filing in Exhibit RMP__(SRM-3) was presented. In discussing each of the adjustments in this testimony, the Utah amounts are based on PacifiCorp's allocation factors associated with the revised protocol method so that the adjustments are comparable to the basis presented by the Company in its exhibits. They are being presented on a revised protocol method for comparison purposes only. The OCS's overall recommended revenue requirement in this case in calculated based on the rolled-in allocation methodology.

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

A. Rocky Mountain Power's filing shows a requested increase in revenue requirement of $228,795,622 based on the revised protocol method, increased to $232,416,309 based on a 100.19% rate mitigation premium.

Based on the OCS' analysis, the Company's request is significantly overstated by an amount of $192,175,529. As shown on Exhibit OCS 3.1, page 3.0, the Office of Consumer Services recommends an increase in the current level of Utah revenue requirement of $40,240,780 based on the rolled-in allocation methodology.

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

A. I first present my recommended rate base adjustments, followed by recommended adjustments to net operating income. At the end of this testimony, I recommend a revision to the line loss factors which impact the energy loads for jurisdictional allocation.

<u>RATE BASE ADJUSTMENTS</u>

Q. WHAT ADJUSTMENTS TO RATE BASE DO YOU SPONSOR?

A. First, I discuss some changes that need to be made to the accumulated deferred income tax (ADIT) inputs into the JAM model presented by the Company to correct several errors that RMP agrees should be made.

Additionally, I discuss revisions that may be needed to the ADIT balances to reflect an updated IRS interpretation of bonus depreciation eligibility. I am also sponsoring adjustments to RMP's projected pro forma plant additions, along with the associated impact on accumulated depreciation.

<u>Accumulated Deferred Income Taxes – Correction of Model Error</u>

Q. ARE ANY CORRECTIONS NEEDED WITH REGARDS TO HOW ACCUMULATED DEFERRED INCOME TAXES WERE INPUT INTO THE COMPANY'S JURISDICTIONAL ALLOCATION MODEL?

A. Yes. DPU Data Request 7.58 asked the Company to describe and explain any changes from the prior case in the jurisdictional allocation model, rate base related templates, or deferred tax calculations. As part of its response, in a footnote, the Company indicated that the "Allocation factors on these accounts were properly assigned in the last general rate case and were inadvertently not corrected in the current general rate case." As a result, the Company was asked in OCS Data Request 14.1 to identify the impacts on the filing that would result from the needed corrections and to include the workpapers and calculations, as well as specific identification of where in the JAM the changes need to be made to correct the Company's errors. In response to OCS Data Request 14.1, RMP indicated that correction of the error would result in a reduction to revenue requirement of approximately $112,276 on a Utah basis. The response also provided specific cell reference within the JAM and identified specifically what numbers and cells within the model need to be corrected.

Q. ARE YOU REFLECTING THIS CORRECTION IN YOUR RECOMMENDATION?

A. Yes. In inputting the OCS's recommended adjustments in this case into the JAM, I first corrected the Company's model specifically making the changes to the cells identified in the Company's response to OCS 14.1. Additionally, I have included a column OCS Exhibit 3.2, which is a summary of the OCS's recommended adjustments, reflecting the reduction in rate base resulting from the correction. In response to OCS 14.1, the Company showed that correction of the amounts it input in its JAM model results in a $2,841,722 reduction to rate base on a total Company basis, or $966,730 on a Utah basis. The Company's estimated revenue requirement impact of that reduction, based on its requested rate of return, is $112,276. On OCS Exhibit 3.2, I reflect the reduction in rate base of $966,730 on a Utah basis. However, for purposes of calculating the final impact on revenue requirement, I input the Company's changes within the jurisdictional allocation model.

<u>ADIT-Impact of Revenue Procedure 2011-26</u>

Q. DID THE COMPANY REFLECT THE IMPACT OF BONUS DEPRECIATION ON THE ACCUMULATED DEFERRED INCOME TAX OFFSET TO RATE BASE INCLUDED IN THIS CASE?

A. Yes, the Company's filing includes its estimates of the impact of bonus depreciation on the 13-month average test year rate base in this case. Thus, the impact resulting from the allowance for bonus depreciation that was created as a result of both the Small Business Jobs Act of 2010, signed into law on September 27, 2010, and the Tax Relief Unemployment Insurance Reauthorization and Job Creation Act of 2010, signed into law by President Obama on September 7, 2010, is included in the adjusted test year average rate base. Thus, once rates go into effect as a result of the Commission Order in this case, customers begin to receive the benefit of the bonus depreciation as it results in a higher ADIT balance, or a lower average test year rate base amount.

RMP included its best estimate of the impacts of bonus depreciation based on information available to the Company at the time it prepared its filing.

Q. HAVE ANY EVENTS OCCURRED SINCE THE TIME THE COMPANY PREPARED ITS FILING THAT WOULD IMPACT THE AMOUNT OF

BONUS DEPRECIATION AND ASSOCIATED ADIT OFFSET TO RATE BASE FOR THE FUTURE TEST YEAR ENDING JUNE 30, 2012?

A. Yes. After the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creations Act of 2010 ("Act") was signed into law on December 17, 2010, it was determined that the Internal Revenue Service (IRS) and the U.S. Treasury Department (Treasury) had different interpretations of what is eligible for the 100% bonus depreciation. On March 29, 2011, the IRS issued Revenue Procedure 2011-26 which clarified the rules for implementing the 100% bonus depreciation provisions and gave more guidance regarding the timing of projects and evaluating whether projects qualified for the 100% bonus depreciation.

The issuance of Revenue Procedure 2011-26, will impact several of the projects that the Company had incorporated in the filing.

Q. HAVE YOU REFLECTED THE IMPACT OF IRS REVENUE PROCEDURE 2011-26 ON THE REVENUE REQUIREMENTS IN THIS CASE?

A. No, not at this time. However, I agree that changes should be reflected and will carefully review additional information provided by the Company on this topic.

Q. WITH THESE CORRECTIONS, WOULD ALL OF THE IMPACTS OF BONUS DEPRECIATION BE INCLUDED IN RATES CHARGED TO CUSTOMERS?

A. Yes, for periods beginning with the rate effective date resulting from this rate case. However, it does not address the lost benefits of bonus depreciation for periods prior to the rate effective date resulting from this case. The lost benefits from prior periods are being addressed by the OCS and will be considered by the Commission in Docket No. 11-035-47.

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<u>Pro Forma Plant Additions</u>

Q. COULD YOU PLEASE BRIEFLY DESCRIBE RMP'S ADJUSTMENT FOR PRO FORMA PLANT ADDITIONS AND RETIREMENTS?

A. Yes. In determining the average test year plant in service, the Company began with the actual June 30, 2010 plant balances. It then forecasted plant additions and retirements for the period July 1, 2010 through June 30, 2012. The plant additions and retirements were projected on a month-by-month basis so that the 13-month average test year plant in service balance could be derived. In Exhibit RMP__(SRM-3), Pages 8.8 and 8.8.1 through 8.8.34 presented RMP's projected additions and retirements. Based on the exhibit, RMP's pro forma plant additions and retirement adjustment incorporates $3.57 billion of plant additions and $410 million of plant retirements for the period July 1, 2010 through June 30, 2012, resulting in net plant additions of $3.16 billion. If the distribution plant that is Situs (100% allocation) to the non-Utah states is excluded, the net increase in the average pro forma plant included in the test year is $2.94 billion. These amounts exclude the additions related to the Trapper Mine, Jim Bridger Mine and Klamath, which are separately adjusted for in RMP's filing.

Q. HOW DO THE ACTUAL PLANT ADDITIONS FOR THE PERIOD FROM THE END OF THE BASE YEAR TO THE MOST RECENT DATE AVAILABLE COMPARE TO THE PROJECTED ADDITIONS CONTAINED IN THE FILING FOR THAT SAME PERIOD?

A. In its Third Supplemental Response to DPU Data Request 2.1, RMP provided the actual monthly capital additions and retirements for the period July 1, 2010 through March 31, 2011 in a similar format as the workpapers that support its filing. Exhibit OCS 3.3, page 3.3.1, presents the total actual plant additions and retirements for each month, July 2010 through March 2011, as compared to the capital additions and retirements contained in the Company's filing for each of the respective months.

As shown on the exhibit, for the nine-months ended March 31, 2011, the actual capital additions are $1,548,130,864, which is $70,246,220 – or 4.34% -- less than the $1,618,377,084 contained in the filing for that same period. Thus, by nine months into the interim period, or two months prior to the start of the test year, RMP's capital additions were $70.25 million below the projected amount. The exhibit also shows that for the same period, the actual plant retirements are $231,572,977, which is $81,709,623 -- or 54.52% -- more than the $149,863,354 contained in the filing. On a combined basis, the result is that the net changes to plant in service is $151,955,843, or 10.35%, less than projected by RMP for that same nine month period.

Q. CONSIDERING THE AMOUNT BY WHICH THE NET PLANT ADDITIONS ARE UNDER-BUDGET AS COMPARED TO THE AMOUNTS ASSUMED IN RMP'S FILING, DO YOU RECOMMEND THE NET PLANT ADDITIONS INCORPORATED IN THE FILING BE REDUCED?

A. Yes. I am recommending a two-step adjustment. I recommend that: (1) the pro forma net plant additions and retirements be reduced to reflect the impact of replacing the projected additions and retirements for the period July 2010 through March 2011 with the actual amount; and (2) the pro forma plant additions be further reduced as a result of applying an over-projection factor.

In the first adjustment, presented on Exhibit OCS 3.3, I reduce the average test year net plant additions to reflect the impact of the actual known net additions for the period July 2010 through March 31, 2011. In calculating the adjustment, I used RMP's adjustment workpapers and replaced the budgeted July 2010 through March 2011 plant additions and retirements with the actual amounts. The result is a $130,115,764 reduction ($62,650,818 Utah) to the average test year plant in service, exclusive of the distribution plant that is fully allocated to other states.

Q. WHAT IS THE SECOND ADJUSTMENT YOU ARE RECOMMENDING?

A. As indicated above, RMP over-projected its plant additions by 4.34% and under-projected its plant retirements by 54.52% for the first nine months following the end of the base year. On a net basis, plant additions were over-projected by 10.35% for that same period. Considering that the projections for the first nine months of additions were overstated, coupled with RMP's history of over-projecting plant additions in prior rate case proceedings, it is not reasonable to assume that RMP's forecasted plant additions for the remaining 15 months between April 2011 through June 2012 are accurate. At this time, I recommend that the remaining monthly plant additions incorporated in the forecast for the period April 2011 through June 2012 be reduced by 4.34% in determining the average test year plant in service balance. This is based on the 4.34% over-projection of the plant additions for the first 9 months following the base year. Since I am leaving the projected retirements at the level projected by RMP, and have not factored in a larger variance for months further out, an even larger adjustment may be warranted.

In calculating the impact of the 4.34% reduction to the monthly plant additions, I began with my revision to RMP's workpapers in which I replaced the projected additions and retirements with the actual balances through March 2011, discussed above. I then applied a 4.34% reduction factor to the Company's projected plant additions for the period April 2011 through June 2012. The result, presented on Exhibit OCS 3.4, is an additional $43,272,559 reduction ($20,931,866 Utah) to the average test year plant in service, exclusive of the distribution plant that is fully allocated to other states.

Q. HAS RMP OVERPROJECTED ITS PLANT ADDITIONS IN PRIOR RATE CASES THAT HAVE UTILIZED FUTURE TEST PERIODS?

A. Yes, RMP has consistently over-projected its plant additions. In RMP's prior rate case, Docket No. 09-035-43, I presented testimony, filed on October 8, 2009, showing that RMP's capital additions were over-projected based on a comparison of eight months of actual data to the projected data contained in the Company's filing. In that testimony, I showed that for the first eight months after the end of the base year, or the months of January 2008 through August 2008, RMP over-projected its plant additions by 5.77%.

In DPU Exhibit 2.0, filed on March 9, 2011 in this case (Docket No. 10-035-124), DPU witness Matthew Croft presented the following findings:

> 1) From an adjusted and weighted average perspective, the Company has over forecasted its plant additions in the previous five rate case filings.
> 2) From a non-adjusted but weighted average perspective, the Company has over forecasted its plant additions in three of the last five rate case filings.
> 3) Eight of the ten weighted average scenarios performed in this analysis yielded an absolute dollar deviation between forecasted and actual plant additions that increased over time.
> (p. 3 – footnotes excluded)

Q. HAVE YOU CALCULATED THE IMPACT OF YOUR RECOMMENDED REDUCTION TO PLANT IN SERVICE ON TEST YEAR DEPRECIATION AND AMORTIZATION?

A. Yes. My recommended reductions to test year depreciation and amortization expense and the depreciation reserve are reflected on Exhibits OCS 3.5 and OCS 3.6, respectively. In determining the adjustments, I utilized the depreciation rates incorporated in the Company's depreciation expense adjustment in Section 6 of Exhibit RMP__(SRM-3). As shown on Exhibits OCS 3.5, depreciation and amortization expense should be reduced by $4,004,248 ($1,941,390 Utah). In estimating the impact on the depreciation reserve, I applied a 50% factor to the recommended reduction to depreciation expense to reflect the average test period rate base impact, reducing the depreciation reserve by $2,001,124 ($970,695 Utah).

Q. DOES YOUR ADJUSTMENT TO REFLECT THE HIGHER PLANT RETIREMENTS FOR THE PERIOD JULY 2010 THROUGH MARCH 2011 ALSO IMPACT THE DEPRECIATION RESERVE?

A. Yes. When an asset is retired from plant in service, the depreciation reserve is reduced by the same amount to remove the asset from the depreciation reserve. On Exhibit OCS 3.7, I reflect the impact on the deprecation reserve resulting from the adjustment to reflect the actual plant retirements through March 2011. The adjustment reduces the depreciation reserve balance by $73,634,085 ($41,234,541 Utah). Plant retirements would have $0 impact on rate base as the plant in service and the depreciation reserve are offsetting entries; however, there is an impact on depreciation expense as the assets being retired will no longer be depreciated in the test year. The impact on depreciation expense is factored into the depreciation expense adjustment on Exhibit OCS 3.5.

<u>Klamath Hydroelectric Settlement Agreement</u>

Q. ON EXHIBIT RMP__(SRM-3), PAGE 8.12, THE COMPANY INCLUDED SEVERAL ADJUSTMENTS ASSOCIATED WITH THE KLAMATH HYDROELECTRIC SETTLEMENT AGREEMENT. IS THE OCS PROPOSING ANY REVISIONS TO THE COMPANY'S ADJUSTMENT?

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

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

A. The necessary adjustments are reflected on Exhibit OCS 3.8 and impact rate base and operating expenses in this case. On Exhibit OCS 3.8, the following adjustments are presented:

- The increase in operation and maintenance costs resulting from the KHSA added by the Company to the test year in this case of $4,150,271 on a total Company basis are removed.
- The Company's proposed increase in rate base of $73,685,107 for the Klamath re-licensing and settlement process costs are removed.

- The Company’s proposed annual amortization of the Klamath re-licensing and settlement process costs of $8,187,234 are removed.
- The Company’s proposed acceleration of the depreciation resulting from the early retirement, as well as the depreciation of new assets recently added due to the KHSA, are being removed. On a combined basis, these items caused depreciation expense to increase by $4,542,733 above the base year level.
- RMP increased the average test year plant in service balance by $2,463,664 for various projects placed into service between July 2010 and December 2011 associated with the Klamath Implementation Project. These costs are also being removed from rate base.
- In RMP’s JAM model, it assigns $7,271,561 to Utah in Account 557 UT under the rolled-in allocation method for Facilities Removal Surcharge costs. These costs are reversed in the OCS’s JAM model calculations, which use the rolled-in allocation method. This is not itemized on Exhibit OCS 3.8, but is identified in a notation on the exhibit, as the exhibit uses the revised protocol method to be comparable to RMP’s presentation.

NET OPERATING INCOME

Powerdale Decommissioning Over-Recovery

Q. WHAT HAS THE COMPANY INCLUDED IN THIS CASE FOR THE AMORTIZATION OF THE DECOMMISSIONING COSTS ASSOCIATED WITH THE POWERDALE HYDRO FACILITY?

A. Since the costs would be fully amortized prior to the start of the rate year in this case, the Company removed the amortization of the decommissioning costs that was recorded on its books during the base year. This adjustment was made by the Company in Exhibit RMP__(SRM-3), at page 8.10.

Q. NOW THAT THE COMPANY HAS FULLY AMORTIZED THE DECOMMISSIONING COSTS, ARE THERE ANY REMAINING ISSUES ASSOCIATED WITH THE POWERDALE HYDRO DECOMMISSIONING THAT NEED TO BE ADDRESSED?

A. Yes, there are. In RMP's rate case Docket No. 07-035-93 and in the subsequent rate case, Docket No. 08-035-38, the Company amortized its projected decommissioning costs of $5,949,952 over a period of three years, effective beginning January 1, 2008. Therefore, between January 1, 2008 and December 31, 2010 amortization expense that has been recovered in rates has totaled $5,949,952. The actual costs incurred by RMP to decommission the facility have been significantly less than the amount the Company presented in its projections in the prior cases; thus, ratepayers have over paid for the decommissioning of the Powerdale hydro facility.

Q. WHAT IS THE ACTUAL COST ASSOCIATED WITH THE DECOMMISSIONING OF THE POWERDALE HYDRO FACILITY AS COMPARED TO THE AMOUNT THAT THE COMPANY HAS BEEN RECOVERING FROM CUSTOMERS?

A. According to the response to OCS 15.11, the Company incurred actual decommissioning costs of $3,797,954 through March 31, 2011 and projects to spend an additional $486,000, resulting in total decommissioning costs of $4,283,954. This is $1,665,998 less than what was authorized in the decommissioning amortization that is being recovered from the Company's ratepayers.

Q. HAS THE COMPANY ESTABLISHED A REGULATORY LIABILITY ON ITS BOOKS TO ACCOUNT FOR THE DIFFERENCE BETWEEN ITS PROJECTED POWERDALE HYDRO DECOMMISSIONING COSTS USED FOR ESTABLISHING THE ANNUAL AMORTIZATION EXPENSE AND THE ACTUAL COSTS INCURRED?

A. I have seen no information to indicate that the Company has established a regulatory liability or a negative regulatory asset to account on its books for this over recovery of the Powerdale decommissioning costs. When the

Company was asked in OCS 15.11(i) why the over recovery of decommissioning costs were not reflected as an offset to rate base and not being flowed back to customers as a negative amortization in this case, RMP stated that:

> The $1.9 million reduction to the estimated decommissioning is reflected as direct reduction to the regulatory asset and the corresponding regulatory offset. The Company will amortize $1.9 million less of decommissioning costs than it originally anticipated as a result of the reduction to the regulatory asset.

In other words, for book purposes the Company only amortized the actual decommissioning costs it incurred. However, for regulatory purposes the Company has been including amortization expense in the last several rate cases based on the originally projected costs of almost $6 million. The Company has booked as amortization expense an amount that is less than the amortization expense authorized by the Commission for inclusion in rates. Had the Company booked the amortization at the level authorized by the Commission, a negative regulatory asset, or a regulatory liability, would have resulted on its books.

Q. WHAT IS YOUR RECOMMENDATION IN THIS CASE WITH REGARDS TO THE OVER RECOVERY OF THE DECOMMISSIONING COSTS?

A. As shown on Exhibit OCS 3.9, the amount of amortization that was authorized in the two prior rate cases, which was based on the Company's projected cost of approximately $5.95 million, exceeds the actual costs incurred and projected to be incurred by $1,665,998. The Company should have booked amortization expense based on the amount authorized by the Commission, which would have resulted in a negative balance in the Powerdale Hydro decommissioning regulatory asset account for the $1,665,998. I recommend that this over recovery, which should in effect be a regulatory liability to the Company, be returned to customers over a period of two years. The result is an annual reduction to expense of $832,999, or $360,555 on a Utah basis to return this regulatory liability to customers.

Q. WHY DID YOU RECOMMEND A TWO YEAR AMORTIZATION PERIOD?

A. The Company has been recovering the projected decommissioning costs from customers with an amortization that began January 1, 2008 and lasted three years. The over recovery should be returned to customers over a period of two years so that the customers who paid the excess costs would be returned those funds. The return of those funds should begin with the rates effective in this case.

<u>RMP Update to REC Revenue Projection</u>

Q. IN THE DIRECT TESTIMONY OF STEFAN A. BIRD, AT PAGES 8 AND 9, MR. BIRD INDICATES THAT THE COMPANY SUBMITTED A

PROPOSAL TO SELL RECS TO NV ENERGY AND THAT THE COMPANY WOULD UPDATE ITS REC REVENUE FORECAST IN THIS CASE IF IT IS SUCCESSFUL IN ITS BID. WAS THE COMPANY SUCCESSFUL IN ITS BID AND HAS IT UPDATED ITS REC REVENUE FORECAST?

A. Yes. The Company entered into a Nevada Energy contract for the sale of RECs. In the first supplemental response to DPU 10.52, RMP provided an update to the REC revenue adjustment contained in its initial filing. The revised top sheet for the Company's REC revenue adjustment for the test period, which was provided as Attachment DPU 10.52-1, first supplement, is not confidential; however, the backup supporting the amounts contained in the revised adjustment is.

Q. WHAT IS THE IMPACT OF THE COMPANY'S REVISION TO REC REVENUES?

A. On Exhibit OCS 3.10, I present the total amount of REC revenue adjustment that is allocated to Utah using the SG allocation factor, from both the Company's original filing and in RMP's total adjustment to REC revenues from its updated adjustment. As shown on Exhibit OCS 3.10, the Company's updated REC revenue adjustment that was presented in the first supplemental response to DPU 10.52 results in an increase of $41,550,512 on a total Company basis that is allocated to Utah using the SG allocation factor to the REC revenues incorporated in the Company's original filing. Using the SG allocation factor, the amount of increase on a Utah basis is $17,984,724. These additional revenues should be reflected in the adjusted test year in this case.

Q. AFTER THE COMPANY'S UPDATE, WHAT IS THE TOTAL FORECASTED REC REVENUES ON A TOTAL COMPANY BASIS THAT ARE INCORPORATED IN THE TEST YEAR ENDING JUNE 30, 2012?

A. RMP's original filing projected total REC revenues for the test year of $55,712,225. In its update to the filing, the Company increased the forecasted REC revenues for the test year to $86,147,420, which is an increase of $30,433,195 on a total Company basis.

Q. WHY IS THE RESULTING ADJUSTMENT TO BE ALLOCATED USING THE SG ALLOCATION FACTOR OF $41.55 MILLION HIGHER THAN THE TOTAL INCREASE IN REC REVENUES OF $30.4 MILLION?

A. In order to meet future year renewable portfolio requirements in California, Oregon and Washington, PacifiCorp has indicated that it will not sell the portion of RECs that are allocated to those states during the test year. As a result, the Company's REC revenue adjustment reallocates the portion of the REC revenues that would otherwise be allocated to California, Oregon and Washington under the SG factor to the remaining jurisdictions, including Utah, consistent with the agreement with the Multi-

State Process. Thus, the increase in projected REC revenues reflected in the update is $30,433,195. However, an additional $11,117,317 is reflected in RMP's update to be allocated to Utah using the SG allocation factor as a result of the re-allocation of the amounts that would otherwise be allocated to California, Oregon and Washington in the allocation model. The total impact that needs to be input into the jurisdictional cost allocation model is an increase in amounts allocated using the Account 456 SG allocation of $41,550,512. The adjustment presented on Exhibit OCS 3.10 does not modify this approach that was used by RMP in its filing and the update thereto.

<u>Additional REC Revenues</u>

Q. WOULD YOU PLEASE BRIEFLY DISCUSS HOW RMP PROJECTED THE AMOUNT OF RENEWABLE ENERGY CREDIT REVENUES INCORPORATED IN ITS ORIGINAL FILING?

A. The calculation of the Company's forecasted REC revenues for the future test year was presented by RMP in Exhibit __(SRM-3), page 3.4.2, and was discussed in the direct testimony of Stefan A. Bird. In forecasting REC revenues, the Company's calculation began with the total projected wind generation for the test year that is incorporated in its case, with each wind generated MWH equaling one REC from wind generation. The resulting total projected volume of RECs based on the wind resources in the Company's test year forecast was then reduced to remove the RECs that are banked to satisfy the renewable portfolio standards (RPS) in California, Oregon and Washington. After accounting for the RPS banking requirements, RMP then applied a 75% factor to the remaining wind MWHs, or RECs, available for sale, reflecting projected sales of RECs based on 75% of its total projected RECs available. On Company Exhibit RMP__(SRM-3), page 3.4.2, the resulting amount is shown as the Company's projected RECs to be sold in the test period. In its adjustment, RMP then separates the resulting amounts between the already known wind sales that are committed to for the test year and the remaining RECs. These exclude the 25% that were removed through RMP's application of the 75% factor and exclude the RECs reserved for California, Oregon and Washington RPS requirements banking.

For the known wind sales that are committed to for the test year, the Company reflected the projected revenues based on known amounts. For the remaining available wind credits that the Company incorporated in its filing to be sold during the test year, the Company applied a price of $7 per REC.

The Company's projections also incorporate a projected sale of vintage RECs, which is based on its projection of the amount of RECs remaining from the previous period, or the 12 months ending June 2011. For the projected vintage REC sales, RMP applied a price of $4 per REC.

All of these Company assumptions result in the projected test year REC revenues contained in the original filling of $55,714,225. As indicated previously in this testimony, in its first supplemental response to DPU 10.52, RMP increased its projected test year REC revenues to $86,147,420.

Q. WHAT REVISIONS DID THE COMPANY MAKE TO THE ORIGINAL FORECAST THAT IT PRESENTED IN EXHIBIT RMP__(SRM-3), PAGE 3.4.2 IN ITS UPDATED PROJECTION, WHICH REFLECTED THE NV ENERGY CONTRACT?

A. In its first supplemental response to DPU 10.52, RMP provided a confidential revised version of page 3.4.2 of its filing. *****BEGIN CONFIDENTIAL** [redacted]

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

The Company's original projections incorporated in its filing at page 3.4.2 excluded non-wind related REC sales from its forecast.

Q. WHY DID THE COMPANY APPLY A 75% FACTOR TO DETERMINE THE AMOUNT OF RECS TO BE SOLD IN THE TEST PERIOD FOR PURPOSES OF PROJECTING THE TEST YEAR REC REVENUES?

A. In the direct testimony of Stefan A. Bird, at page 3, he indicates that the Company sells only 75% of the forecast wind RECs <u>on a forward basis</u> "...to insure it can perform under any contracts, bundled or unbundled, that it may enter into." His testimony also indicates that based on the Company's experience so far coupled with the wind data that it has received, selling 75% on a forward basis ensures that the Company can perform under its contracts and avoid exposing the Company to costs associated with liquidated damages or non-performance.

Q. DO MR. BIRD'S STATEMENTS MEAN THAT THE COMPANY WILL ONLY SELL 75% OF THE WIND RELATED RECS THAT ARE

GENERATED DURING THE TEST YEAR THAT ARE NOT BEING BANKED FOR RPS COMPLIANCE REQUIREMENTS?

A. No, it does not. It simply means that the Company sells only 75% of the forecasted wind RECs on a "forward basis". If RMP is able to generate RECs above the 75% level, it will have the ability to offer any remaining RECs for sale in the market. The Company has provided no justification for its assumption that it will not sell the remaining 25% of the RECs that its filing projects it will produce during the test year in this case.

Q. HOW HAS THE HISTORIC PERCENTAGE OF WIND GENERATED RECS SOLD IN EACH YEAR COMPARED TO THOSE PRODUCED?

A. After removing the amount associated with RPS banking requirements, *****BEGIN CONFIDENTIAL***** [redacted] *****END CONFIDENTIAL*****

Q. DO YOU RECOMMEND THAT THE 75% FACTOR APPLIED BY THE COMPANY AND DISCUSSED IN THE DIRECT TESTIMONY OF MR. BIRD BE REVISED?

A. Yes. In this case, I recommend that the 75% factor be increased to 90%, reflecting a projection that the Company will sell 90% of its wind related RECs that it projects to produce during the test year. This is after removal of the RPS banking requirement factors for the states of California, Oregon and Washington.

Q. IS THE COMPANY'S PROJECTED SALES PRICE OF $7 PER REC FOR THE REMAINING AVAILABLE WIND-RELATED RECS A REASONABLE PROJECTION?

A. No, it is not. It is my opinion that it is significantly understated.

Q. HAS THE COMPANY BEEN SUCCESSFUL IN PAST CASES IN PROJECTING THE REC SALES PRICE?

A. No. In the last rate case, Docket No. 09-035-23, the Company significantly under projected the amount of revenues to be produced from the sale of RECs and substantially under projected the price per REC.

Q. COULD YOU PLEASE ELABORATE?

A. Yes. The Company's last rate case incorporated a future test period ending June 30, 2010. In its original filing, RMP projected total REC revenues of $7,411,125. This assumption included a projected sales price per wind related REC sold of $3.50. It also assumed that only 75% of the available MWHs would be sold after removal of the RPS banking requirements. In response to an OCS recommended adjustment to the projected REC revenues, RMP increased its projected test year ended June 30, 2010 REC revenues in rebuttal testimony from the $7.4 million in its initial filing to $18.5 million. However, as shown in Exhibit RMP__(SRM-3), page 3.4 of the current case, the actual booked REC revenues for the base year ended June 30, 2010 was $98,525,363. In other words, the Company's rebuttal position in the last rate case under forecast the REC revenues for the period ended June 30, 2010 by over $80 million.

By the time of hearings in the last general rate case, and possibly by the time it filed the rebuttal testimony in that case, the Company would have been aware of the substantial increase in the price per REC that was occurring, yet it chose not to inform the parties of this information either prior to or during the hearings in that case.

Q. HOW HAVE RECENT SALE PRICES PER REC COMPARED TO THE $7 PER REC ASSUMPTION INCORPORATED IN THE COMPANY'S FILING IN THIS CASE?

A. In the table below I present the actual average wind related REC sales price received by the Company in 2010, as well as the Company's forecast average wind related REC sales price for 2011 and 2012. These amounts were provided by the Company in its confidential responses to UAE 5.3 and UAE 5.4.

*****BEGIN CONFIDENTIAL*****

Redacted

[redacted]

Q. [redacted]

A. [redacted] *****END CONFIDENTIAL*****

Clearly, based on the sale prices for the last few years and known contracts, the Company's projection of $7 per REC for the remaining available wind credits that are not under contract is not a reasonable or realistic assumption.

Q. WHAT AMOUNT DO YOU RECOMMEND BE USED FOR THE REMAINING AVAILABLE WIND CREDITS THAT ARE NOT

CURRENTLY UNDER CONTRACT FOR THE TEST YEAR IN THIS CASE?

A. I recommend that the amount be calculated based on a price per REC of $36. It is my opinion that this is a more reasonable assumption than the $7 per REC incorporated in the Company's projections.

Q. WHAT OVERALL ADJUSTMENT DO YOU RECOMMEND?

A. As shown on Exhibit OCS 3.11, I recommend that the Company's updated REC revenue projections be increased by an additional $44,538,991 on a total Company basis, resulting in total OCS recommended REC revenues for the test year ending June 30, 2012 of $130,686,411. The impact on a Utah basis is an increase in Utah allocated REC revenues of $26,461,642.

In calculating this amount I used the same assumptions and calculations used by the Company and its updated REC revenue projection provided in its first supplemental response to DPU 10.52. The only changes I have made were to increase the percent sold from the amount in the Company's update to 90%, and to increase the price per REC for the remaining wind credits that are not under contract from the amount in the Company's update to a price of $36 per REC.

Q. COULD THE AMOUNT OF REC REVENUES TO BE COLLECTED BY THE COMPANY DURING THE FUTURE TEST YEAR ENDED JUNE 30,

2012 BE HIGHER THAN THE AMOUNT INCLUDED IN YOUR FORECAST?

A. Yes, it could. The Company's original forecasted REC revenues did not include any amounts associated with non-wind related REC sales. However, historically the Company has sold RECs generated from assets other than wind, such as hydro RECs and RECs created by the Blundell facilities. It is not reasonable to assume that there will be no non-wind related REC sales in the test year.

Q. DO THE COMPANY'S UPDATED PROJECTIONS INCLUDE ANY PROJECTED REVENUES ASSOCIATED WITH NON-WIND RELATED REC SALES?

A. *****BEGIN CONFIDENTIAL***** [redacted] *****END CONFIDENTIAL***** However, it is likely that the Company will sell additional non-wind related RECs during the test year. At this time I have not included an adjustment to incorporate additional non-wind related REC sales. As a result, the projected REC revenues in my recommendation may be understated.

Q. GIVEN THE COMPANY'S RECORD REGARDING THE PROJECTION OF REC REVENUES AS WELL AS THE VOLATILITY IN THE REC MARKET, SHOULD ANY SAFEGUARDS BE PUT INTO PLACE TO PROTECT RATEPAYERS IN THE EVENT THAT THE AMOUNTS YOU ARE PROJECTING IN THIS CASE ARE UNDERSTATED?

A. Yes. REC sales and REC revenues are impacted by many factors such as the amount of RECs produced and purchased in a year, the amount of RPS banking requirements, as well as the amount the Company sells in any given year. They are also impacted by factors such as whether they are sold as a bundled product with the energy or as an unbundled REC. RECs that are produced in a year and not sold within that year (Vintage RECs) still exist and can be sold in future periods. Additionally, various states have recently changed and are still changing renewable energy portfolio requirements thereby impacting the market. The addition of transmission allowing for the bundling of more RECs with the energy produced can also impact the sales level and prices. These factors, as well as others, result in changes and uncertainties in the REC market and fluctuations in the prices available for REC sales. There are also many opportunities for the Company to manipulate the amount of REC sales within a 12 month period, which can negatively impact ratepayers.

Given the amount of volatility, uncertainty and fluctuation, as well as the ability of the Company to control the amount and timing of sales to some degree, I recommend that RMP be required to record the difference between the amount of REC revenues approved by the Commission in this case for inclusion in rates and the actual REC revenues realized, with any differences being recorded in a regulatory deferral account. As ratepayers are paying for the wind facilities and other generation facilities that produce the RECs, they should also receive the benefit of the revenues generated from the REC sales. Additionally, interest should be imputed on the amount deferred. At the time of the next rate case, the balance in the regulatory deferral account could be amortized. I recommend that this regulatory deferral treatment remain in place for the next several rate cases and can be reconsidered at a future time.

At the time of the next rate case following this case, any deferred balance would be amortized as part of the revenue requirement. The annual REC revenue level can be reviewed and possibly reset for inclusion in base rates based on facts and information available at that time. Following the next rate case, the regulatory deferral treatment would continue based on the amount incorporated in the base rates. This mechanism would protect both customers and the Company. As I recommend the deferrals accumulate interest, this would give the Company incentive to project a realistic amount in its rate case filings.

Deferred REC Balancing Account

Q. WOULD YOU PLEASE BRIEFLY DESCRIBE THE DEFERRED REC BALANCING ACCOUNT ESTABLISHED IN DOCKET NO. 10-035-14?

A. In the Commission's Report and Order on Deferred Accounting Stipulation for Docket Nos. 09-035-15 and 10-035-14, issued July 14, 2010, the Commission ordered that the Company would record incremental REC revenues in accordance with the terms and conditions of a Stipulation in a separate deferred account, or a Deferred REC Balancing Account. The Stipulation provided that the Company would "…defer incremental REC revenue in accordance with the UAE Application commencing February 22, 2010." The amount to be deferred was the amount exceeding the REC revenues recognized in the prior rate case, Docket No. 09-035-23. As mentioned previously in this testimony, RMP under-projected REC revenues in Docket No. 09-035-23 by a significant amount.

As part of the Commission's Order Approving Settlement Stipulation issued December 21, 2010, a $3 million per month customer sur-credit was established January 1, 2011. The sur-credit represents incremental REC revenues not reflected in Utah rates and is booked against the Deferred REC Balancing Account thereby reducing the balance.

Q. WHAT SHOULD BE DONE WITH THE BALANCE IN THE DEFERRED REC BALANCING ACCOUNT?

A. I recommend that the balance as of the date of the Commission's Report and Order in this case be flowed-back to ratepayers over a three-year amortization period. RMP should be required to report the balance in the account as of the final date of hearings in this case. Any changes in the deferred account from the final date of hearings through the first day of the rate effective period resulting from this case could be incorporated in the regulatory deferral account recommended in the previous section of this testimony.

Q. WHY SHOULD THE BALANCE BE FLOWED BACK TO RATEPAYERS IN THIS CASE?

A. There are several reasons that the balance in the deferred REC balancing account, which has been approved by the Commission, should flow to ratepayers. First, RMP's customers are funding the significant amount of generation capital investments from which the RECs are derived and the revenues collected as a result of generating the RECs from the operation of those plants should go to ratepayers.

Second, the significant increase in the price received per REC was dramatic, unprecedented and unforeseen at the time RMP initially filed its last rate case, Docket No. 09-035-23.

Third, by the time the hearings began in the last rate case, Docket No. 09-23-035, RMP knew that the per REC price had increased significantly from the per REC price projection incorporated in its initial filing and effectively incorporated in its rebuttal position, yet it chose not to inform the parties of this significant event. Ratepayers should not be harmed by RMP's choice not to disclose this relevant and dramatic information to the parties during its prior rate case.

As previously indicated, RMP's initial filing in Docket No. 09-035-23, which used a future test year ending June 30, 2010, incorporated projected total REC revenues of $7.4 million. In rebuttal to the Office's recommended increase in REC revenues, the Company increased the projected REC revenues to $18.5 million. The actual REC revenues recorded for that same twelve month period was $98.53 million, which is over 13 times higher than the original projection presented in Docket No. 09-035-23 and over 5 times higher than the rebuttal position. RMP should not be allowed to retain ratepayer money by failure to disclose this increase in revenues.

Additionally, the amounts currently recorded in the REC balancing account resulting from the deferred accounting order are for periods from the date the Utah Association of Energy Users ("UAE") filed its request for Deferred Accounting Order forward.

Q. DOES THE OCS RECOMMENDED REVENUE REQUIREMENT PRESENTED IN THIS TESTIMONY INCLUDE THE IMPACT OF AMORTIZING THE DEFERRED REC BALANCING ACCOUNT OVER A THREE-YEAR PERIOD?

A. No, not at this time. I do not have the current balances in the account as of the present date and am uncertain what changes will occur in that account between the present date and the date of the Commission's Report and Order in this docket.

<u>**Insurance Expense**</u>

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

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

Q. COULD YOU PLEASE PROVIDE A TABLE SHOWING THE TOTAL NON-T&D DAMAGE COSTS NOT COVERED BY OUTSIDE INSURANCE THAT THE COMPANY IS PROPOSING TO IDENTIFY AS INTERNAL "INSURANCE EXPENSE" AND THE AMOUNT IT IS PROPOSING TO IDENTIFY AS NON-T&D MAINTENANCE EXPENSE?

A. Yes. The table below provides this breakout, by year, of the amount the Company is identifying as internal "insurance expense" and the amount it is identifying as Non-T&D maintenance expense, as well as the three-year average amount it propose to include in rates.

	Internal Insurance Portion	Maintenance Expense Portion
"Deductible"	*$ 1,000,000*	
Apr 2007 - Mar 2008	$ -	$ 1,038,168
Apr 2008 - Mar 2009	$ 5,410,474	$ 1,373,698
Apr 2009 - Mar 2010	$ 847,444	$ 1,687,636
Average	$ 2,085,973	$ 1,366,501

Q. THE AMOUNTS PRESENTED IN THE TABLE ABOVE ARE SIGNIFICANTLY HIGHER FOR THE TWELVE MONTH PERIOD ENDED MARCH 2009. COULD YOU EXPLAIN WHY THAT PERIOD IS SO MUCH HIGHER THAN THE TWO REMAINING PERIODS PRESENTED?

A. Yes. Included in the total Non-T&D damages cost to the Company for the twelve months ended March 2009 is $6,410,474 associated with high runoff that caused flooding and a landslide that resulted in damage to the Swift hydro facility powerhouse. This event occurred between January 6th

and January 8th, 2009 (hereafter referred to as January 8) and has a significant impact on the Company's proposed Non-T&D damages expense requested in this case. Costs for the following year, the twelve month period ended March 2010, included an additional $847,444 for the same event. Of the total Non-T&D damage costs for the three-year period ended March 31, 2010 of $10,357,420, $7,257,918 is associated with this one event that occurred on January 8, 2009.

The entire balance of the Company's proposed Non-T&D internal "property insurance" cost of $2,085,973 is the result of this one event. In other words, during that three-year period in the Company's analysis, the entire balances that exceed its proposed $1 million internal "insurance deductible" threshold related to the January 8, 2009 high runoff event. Of the Non-T&D maintenance expense requested by the Company (i.e., the amount it is not proposing to be categorized as internal "property insurance"), totaling $1,366,501, $343,333 is associated with January 8, 2009 high runoff event.

Thus, of the Company's total forecasted Non-T&D damages expenses of $3,452,473 not covered by outside insurance, $2,419,306 is the result of the January 8, 2009 high runoff flooding and landslide event.

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

A. Yes. RMP's response to DPU 22.12 provided a listing of costs by work order for the past three years for various damages costs, including those identified as Non-T&D expenses. In OCS Exhibit 3.12, page 3.12.2, I provide a listing of items identified by the Company as having to do with the January 2009 Swift River high runoff event.

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

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

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

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

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

A. On Exhibit OCS 3.12, page 3.12.1, I removed the impact of this January 8, 2009 runoff event for purposes of determining the three-year average cost level. Removing this event in projecting a normalized cost level results in a $2,085,973 reduction to the Company's proposed internal self-funded property insurance costs and a $333,333 reduction to the Company's proposed Non-T&D maintenance expense associated with future damages. In other words, projected test year expenses in RMP's filing should be reduced by $2,419,306. As shown on this same exhibit, this recommendation allows for a normalized level of cost associated with Non-T&D maintenance expenses associated with damages of $1,033,167. These would be for amounts not covered under the Company's insurance policies with outside insurers.

As shown on Exhibit OCS 3.12, Non-T&D insurance and maintenance expenses proposed by the Company should be reduced by $2,419,306 on a total Company basis and $1,047,172 on a Utah basis to exclude the impact of this one-time unusual event for purposes of normalizing these costs.

<u>Generation Overhaul Expense</u>

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

A. In its filing, RMP adjusted the base year generation overhaul expense to reflect a four-year average cost level. In deriving its adjustment, RMP used the actual overhaul costs for the past four years on a plant by plant basis for the plants that were owned for the duration of the four-year period. RMP then added a combination of actual and projected annual costs to derive a four-year average overhaul cost for new plants that were not in service over the entire four-year historic period. The new plants included Currant Creek, Lake Side and Chehalis.

The inclusion of overhaul costs in rates at an average, normalized level is consistent with past Commission decisions and recognizes that the costs can fluctuate significantly from year to year. In the Orders in Docket No. 07-035-93, issued August 11, 2008, and Docket No. 09-035-23, issued February 18, 2010, the Commission included overhaul costs in rates based on a four-year average historic cost level for existing plants, excluding escalation, and a combination of actual and projected four-year average cost level for new generation plants.

Q. DO YOU RECOMMEND ANY REVISIONS TO THE COMPANY'S PROPOSED ADJUSTMENT?

A. Yes. I recommend two adjustments. First, I recommend that the costs associated with the Little Mountain generation plant be removed. Additionally, I recommend that the projected overhaul costs for the period ended June 30, 2011 for the Lake Side plant used in the four-year average be revised to reflect actual costs for the overhaul, which is now complete.

Q. WHY SHOULD THE COSTS ASSOCIATED WITH THE LITTLE MOUNTAIN PLANT BE REMOVED FOR PURPOSES OF NORMALIZING THE TEST YEAR GENERATION OVERHAUL EXPENSE?

A. At page 47 of his direct testimony, RMP witness Steven McDougal indicates that the Company plans to retire the Little Mountain plant in March 2012 after the current steam sale contract expires. In its Incremental Generation O&M expense adjustment, the Company reduced O&M expenses to reflect this projected retirement. Since the Company intends to retire the plant during the test year, it will not incur costs associated with overhauling the plant during the test year or subsequent. Thus, Little Mountain overhaul costs should be removed for purposes of normalizing the generation overhaul costs in the test year.

Q. WHAT AMOUNT IS INCLUDED IN THE NORMALIZED GENERATION OVERHAUL EXPENSE IN THE FILING ASSOCIATED WITH THE LITTLE MOUNTAIN PLANT?

A. RMP's test year normalized generation overhaul expense includes $167,000 ($72,284 Utah) associated with the Little Mountain plant. The calculation of this amount is presented on Exhibit OCS 3.13, page 3.13.1.

Q. WHY SHOULD THE PROJECTED OVERHAUL EXPENSE FOR THE LAKE SIDE PLANT FOR THE YEAR ENDING JUNE 30, 2011 BE REVISED?

A. In determining the average overhaul costs for the Lake Side plant, RMP used actual costs for the years ended June 30, 2009 and June 30, 2010 and projected costs for the years ending June 30, 2011 and 2012. The projected cost included in the filing for the year ending June 30, 2011 is $5,119,000. These projected costs are significantly higher than the projected costs for the Lake Side overhaul during that same time frame that was incorporated in RMP's last rate case filing, Docket No. 09-035-23. In response to DPU Data Request 16.9, the Company provided actual overhaul costs for the Lake Side plant for the period July 1, 2010 through March 31, 2011, which total $3,127,000, and the remaining projected costs for the overhaul to be incurred in April 2011. The total actual and remaining projected costs for the year ended June 30, 2011 is $3,982,000, which is $1,137,000 less than the projected amount included in the filing. As shown on OCS Exhibit 3.13, page 3.13.1, the impact of the over-projection is $284,250 ($1,137,000 / 4 year average). The test year normalized generation overhaul expense should be reduced by $284,250 to reflect the updated Lake Side overhaul costs in determining the normalized cost level.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED REVISIONS TO THE GENERATION OVERHAUL EXPENSE ADJUSTMENT?

A. Exhibit OCS 3.13 presents the adjustment that is necessary to (1) remove the Little Mountain plant costs from the analysis; and (2) reflect the actual and revised projected costs for the recent Lake Side overhaul in deriving the projected average costs. The adjustment reduces the generation overhaul expenses included in RMP's filing by $451,250 on a total Company basis and $195,319 on a Utah basis.

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

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

A. Either during the base year or subsequent, RMP placed three wind facilities, three new transmission resources and a pollution control project at the Dave Johnston Unit 3 plant into service. Between the present time and the end of the future test period, RMP projects to place four additional pollution control projects into service at Wyodak Unit 1, Naughton Unit 2, Dave Johnston Unit 4 and Naughton Unit 1. The Company also has experienced some contract changes associated with managing the gas turbine parts and services contract for the Lake Side plant; switching to a higher SO2 content coal at Cholla 4; and plans to retire the Little Mountain plant during the future test year. Each of these events is projected to result in changes in expenses compared to what is included in the base period. The Company's adjustment increases generation and transmission O&M expenses by $10,818,967 ($4,653,534 Utah) to reflect the incremental costs associated with the changes. The costs being added, with the exception of $85,000 associated with the operation of the three new wind facilities, are all non-labor related costs.

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

A. Yes. I recommend two adjustments be made to RMP's projected incremental generation O&M expenses. The incremental costs associated with the Dunlap I wind facility should be reduced by $178,447 to remove a double counting of costs that were incorporated in the base year. Additionally, the incremental costs included for the Lake Side contract change should be reduced by $827,203 as a result of the renegotiation of the contract.

Q. PLEASE DISCUSS YOUR FIRST RECOMMENDED ADJUSTMENT ASSOCIATED WITH THE DUNLAP I WIND FACILITY.

A. In calculating the incremental generation O&M expense associated with the Dunlap I wind project, the Company projected forecast test year expenses of $2,602,500. It then compared the $2.6 million to the amount of expenses incorporated in the base period, which is identified as $0 on

Exhibit RMP__(SRM-3), page 4.15.1. However, based on the Company's responses to OCS Data Request 15.6, the Company recorded $169,610 on its books in January 2010 with the cost identified as environmental service costs.[1] Based on that same response, the $169,610 that was posted in January 2010 was reversed in August 2010 on the Company's books; however, the August 2010 date would fall outside of the base year. Thus, test year expenses would still include $169,610, and those costs would have been escalated by a factor of 5.21% as part of the Company's escalation adjustment in its filing. As a result, RMP incremental generation O&M expense associated with the Dunlap I wind facilities should be reduced by $178,447 to remove the double count of these costs which were already recorded in the base period in this case. This adjustment is shown on Exhibit OCS 3.14.

Q. PLEASE DISCUSS YOUR RECOMMENDED ADJUSTMENT ASSOCIATED WITH THE LAKE SIDE PLANT CONTRACT CHANGES.

A. RMP increased its base year costs associated with the Lake Side facility by $1,186,718 to reflect the impact of a change and extension of the managed long-term gas turbine parts and services contract it had in place with Siemens. In response to OCS 15.10, RMP indicated that after its initial filing in this case was made, its contract with Siemens for the Lake

[1] RMP's response to DPU Data Request 27.7, Attachment DPU 27.7, page 1 of 2, also confirms $169,610 was recorded during the base year for the Dunlap Wind project.

Side plant was renegotiated and the fee schedule was revised. In the response, RMP indicated that the portion of the contract cost increase related to the quarterly duty cycle fee will now be capitalized instead of expensed on the Company's books. The portion that will now be capitalized is $827,203 of the projected $1,186,718 incorporated in the Company's incremental generation and transmission O&M expense adjustment. Thus, the projected test year expenses should be reduced by $827,203 to reflect the impact of this contract change.

Q. WHAT IS THE OVERALL IMPACT OF YOUR RECOMMENDED ADJUSTMENTS TO THE COMPANY'S INCREMENTAL GENERATION AND TRANSMISSION O&M EXPENSES?

A. As shown on Exhibit OCS 3.14, test year expenses should be reduced by $1,005,650 on a total Company basis and $435,285 on a Utah basis.

<u>Payroll Expense</u>

Q. WHAT AMOUNT IS THE COMPANY REQUESTING IN THIS CASE FOR PAYROLL COSTS AND HOW DOES THAT COMPARE TO THE BASE YEAR COST LEVEL?

A. Company Exhibit RMP__(SRM-3), page 4.16.2, shows that the base year ended June 2010 included $474,780,327 for labor costs inclusive of regular, overtime and premium pay (hereafter identified as "payroll costs").

The Company's filing on that same page reflects a projected increase of $17,631,527, resulting in a projected test year ended June 30, 2012 amount for these payroll costs of $492,411,854. In determining the projected test year cost level, RMP started with the actual monthly payroll costs by labor group for each month of the historic base year and escalated the monthly amounts by both the actual and projected salary and wage increases by labor group. Thus, the base used by the Company would be the monthly payroll for each month in the base year ended June 2010 with escalation factors applied to project the future test year costs by month.

Q. DO YOU HAVE ANY CONCERNS WITH THE APPROACH USED BY THE COMPANY IN PROJECTING THE REGULAR, OVERTIME AND PREMIUM PAY LABOR COST?

A. Yes. As mentioned above, the starting point is the actual labor cost inclusive of regular, overtime and premium pay for each month of the historic base period. However, the actual employee count on a full-time equivalent ("FTE") basis for PacifiCorp has been steadily declining. Response to R746-700-22.D.23 provides the actual FTE employee compliment for PacifiCorp for the period July 2008 through December 2010. Based on this response, the actual FTE employee count at the start of the base year (July 2009) was 5,737.5 employees. That balance steadily declined each and every month throughout the base period used in this case such that the actual end of base period, or June 2010, FTE employee count was 5,586 employees. The PacifiCorp FTE employee compliment declined by 151.5 employees or 2.6% during the base year. The average employee compliment on a full-time equivalent basis for the base period, using the response to R746-700-22.D.23, was 5,655.5 employees. The response also shows that the December 2010 FTE level is 5,586 which is the same as the end of base period level. By taking the actual monthly labor costs in the base period and escalating those amounts, the result is an overstatement of projected labor costs as it would not reflect the full decline in employees that occurred.

Q. IS THERE ANY INFORMATION YOU HAVE SEEN THAT WOULD INDICATE THAT THE EMPLOYEE COMPLIMENT AT PACIFICORP HAS CONTINUED TO DECLINE SUBSEQUENT TO THE END OF THE BASE YEAR USED IN THE COMPANY'S FILING?

A. Yes. While on-site at the Company's Portland, Oregon offices, the Company provided copies of its monthly operating reports. Included within each of the monthly reports is a page that shows the work force levels broken down into various categories. The page shows the actual FTE employee levels for the month as well as the budget for that month and the budget variance.

*****BEGIN CONFIDENTIAL***** [redacted]

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

Based on the above presented employee levels, clearly PacifiCorp's full-time equivalent employee level has declined both during the base period and subsequent to the base period used in this case.

Q. HAS THE COMPANY PROVIDED ANY DOCUMENTS IN THIS CASE THAT WOULD INDICATE THAT THE LOWER FTE EMPLOYEE

COMPLIMENT HAS RESULTED IN O&M COSTS BEING LOWER THAN WHAT WAS BUDGETED IN THE BASE PERIOD AND SUBSEQUENT?

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

Q. IN YOUR OPINION, ARE THE PAYROLL COSTS INCLUDED IN THE COMPANY'S FILING LIKELY TO BE REFLECTIVE OF THE FUTURE TEST YEAR ENDING JUNE 30, 2012?

A. No, it is my opinion that the amounts are over projected. First, it is already known that the employee complement has declined since the average base year level that would effectively be incorporated in the Company's filing. No adjustment was made by the Company to reflect the impact of the reduction in employee levels that occurred during the base year and subsequent. Additionally, the Company has over-projected the payroll costs for each of the last three rate cases in which it used a future test year. During that same period, the employee count has been declining. As the Company is using a similar methodology in forecasting payroll costs in this case, the result is that the payroll costs in this case are also over-projected.

Q. ON WHAT DO YOU BASE YOUR CONTENTION THAT THE COMPANY HAS OVER PROJECTED THE PAYROLL COSTS IN THE LAST THREE GENERAL RATE CASES?

A. On Exhibit OCS 3.15, page 3.15.1, I present the amount of regular, overtime, and premium pay and resulting payroll costs for these three items on a total basis that was projected by the Company in each of the last three rate cases (Docket Nos. 07-035-93, 08-035-38 and 09-035-23) as compared to the actual amounts for those same periods. Each of these cases incorporated future test years. The result was that these costs were over projected by $394,494, $5,842,329 and $11,913,408 in each of these dockets, respectively. On a percentage basis, the over-projections were 0.08%, 1.23% and 2.51%, respectively.

The over projections are most likely the result of the steady decline in employee complement that has not been factored into RMP's rate case filings. As shown on page 3.15.1, the average percentage that the Company has over projected the ordinary time, overtime and premium pay in the last three rate cases has been 1.27%.

Q. WHAT ADJUSTMENT TO PAYROLL EXPENSE DO YOU RECOMMEND IN THIS CASE?

A. As shown on Exhibit OCS 3.15, I recommend that a <u>negative</u> 1.27% be applied to the Company’s projected regular, overtime, and premium pay incorporated in the forecasted test year in this case of $492,411,854. This represents the average percentage by which the Company has over projected regular, overtime and premium pay for the last three rate cases. This results in a recommended reduction to projected labor costs of $6,271,600. As shown on Exhibit OCS 3.15, the result is a recommended reduction to salary and wages expenses incorporated in the filing of $4,342,863 ($1,818,516 Utah) after the expense factor is applied. It is my opinion that this is a conservative adjustment that may not reflect the full impact of the employee reductions that occurred during the base period in this case and subsequent. My recommendation still allows for an $11,359,927 increase in the regular, overtime and premium pay as compared to the actual amount recorded during the base year ended June 30, 2010.

<u>Labor Costs-Energy Trading System Cost Savings</u>

Q. IN EXHIBIT RMP__(SRM-3), PAGE 4.15, THE COMPANY MADE AN ADJUSTMENT TO INCREASE O&M EXPENSES BY $10.8 MILLION ON

A TOTAL COMPANY BASIS AND $4.65 MILLION ON A UTAH BASIS FOR INCREMENTAL GENERATION AND TRANSMISSION O&M EXPENSE. COULD YOU PLEASE GIVE A BRIEF OVERVIEW OF THE PURPOSE OF THIS COMPANY ADJUSTMENT?

A. Yes. As previously discussed, the overall purpose of this adjustment is to include projected incremental operation and maintenance expense resulting from new generation and transmission projects that were either placed into service during the base period or subsequent and those that are projected to be placed into service by the end of the test year in this case. The adjustment also increases O&M expenses for some existing resources due to various known changes.

Q. ARE THERE ANY PLANT ADDITIONS INCLUDED IN THE COMPANY'S FILING THAT WILL RESULT IN COST SAVINGS? IF YES, HAS THE COMPANY REFLECTED THOSE COST SAVINGS IN THIS CASE?

A. In this case in the pro forma plant additions the Company has included in plant in service $14.1 million for the commercial and trading TrIP Energy Trading System Capital. In its filing at page 8.8.47, the Company described the project as follows:

> INTANGIBLE PLANT ADDITIONS
> Commercial & trading TrIP Energy Trading Systems (ETS) Capital:
> (Reference page 8.8.32)
> Replacement of existing systems used in the Commercial & Trading business unit related to trade capture, scheduling, risk management, credit, profit and loss reporting, checkout and settlement. Many of the PacifiCorp Energy commercial & trading

> existing systems are based on outdated technology, are fragmented across business functions, and require a significant amount of manual integration between systems that negatively impact business process efficiency and effectiveness. The goal of this project is to purchase and implement an integrated energy trading system which will replace over 30 existing systems that support trades, scheduling and energy accounting functions.

While the Company has included the capital cost as well as the depreciation or amortization expense associated with this intangible plant addition, it did not include any projected cost savings that will result. As indicated above, the goal of the project is to purchase and implement an integrated system that will replace over 30 existing systems. The existing systems being replaced require significant amounts of manual integration which the Company indicated negatively impacts business process efficiency. Given the magnitude of this project, significant cost savings should result. However, the Company has not incorporated any of the cost savings.

Q. HAS THIS PROJECT BEEN PLACED INTO SERVICE BY THE COMPANY?

A. Yes. According to the Company's response to UIEC Data Request 24.1 the new energy trading system was placed into service by the Company on February 1, 2011.

Q. HAS THE COMPANY PROVIDED THE PROJECTED COST SAVINGS THAT SHOULD RESULT FROM THIS PROJECT?

A. OCS Data Request 6.28 asked the Company to provide a copy of any cost benefit analysis conducted by or for the Company with regards to the new TrIP Energy Trading System and also asked the Company to describe, in detail, any projected efficiency savings that will result from the implementation of this system. The question also asked the Company to provide its current best estimate of any workforce/labor reductions that will result from the replacement of over 30 existing systems with the implementation of the integrated system. Regarding the workforce/labor request, the Company merely responded that “No workforce or labor reductions are currently being forecasted.” However, this does not fully answer the question asked. The Company did provide Attachment OCS 6.28a its analysis in support for the project as well as the cost benefit analysis associated with the project, which was dated August 5, 2008. The Company did not include any updated projections of the benefits that will result from this project beyond the August 5, 2008 document provided with the response. The executive summary supporting the new system included the following statement:

> The net present value associated with the $21.6 million integrated energy trading system project is a positive $11.8 million and IRR of 60.6% due to the various net power cost benefits and operational efficiencies gained from the new system as well as avoiding the $12.4 million required case out flow to upgrade and maintain the current system functionality.

In the Company's previous rate case, the Company incorporated some of the costs of this system as going into service in April 2010 and reflects the majority of the remaining costs in this case as going into service in January 2011. As indicated previously, the Company indicated in response to discovery that the plant project was placed into service February 1, 2011.

Throughout the document supporting the Energy Trading System project there is reference to various cost savings and productivities that are projected to result. At page 5 of 17 of the document, under the section of benefits, it indicates in part that "PacifiCorp Energy business performance will be improved with the reduction of net power costs." It also states that "In addition, the comprehensive analysis performed to capture the business benefits indicates that most benefits will either be achieved as soon as the solution is placed in a production environment (considered 'used and useful') or within the first year following implementation."

Q. ARE YOU RECOMMENDING ANY REDUCTIONS TO COSTS ASSOCIATED WITH COST SAVINGS IN THIS CASE?

A. Yes, in this testimony I am recommending that the projected labor cost savings resulting from implementation of the TrIP Energy Trading System be incorporated in the test year in this case. In the cost benefit analysis presented by the Company it identified several projected reductions in full-time equivalent employee positions that will result from implementation of the project, with those employee reductions shown as occurring six-months after implementation. As the Company has now implemented the system, the labor cost saving should begin early in the future test year used by the Company in this case. Thus, I recommend that those labor cost savings be reflected in the test year.

Q. WHAT ADJUSTMENT NEEDS TO BE MADE TO REFLECT THE PROJECTED LABOR COST SAVINGS?

A. The cost benefit analysis presented by the Company projects the following labor cost savings:

- Reduction of the finance department full-time equivalent position due to efficiencies, with a projected fully loaded salary for that position of $150,000 per year of O&M savings;
- Reduction of up to two middle office full-time equivalent employees as a result of efficiency gained, with resulting fully loaded salaries for the two combined positions of $300,000 a year of reduced O&M costs;
- Reduction of three full-time equivalent head counts in the area of information technology employees-contractors, with the fully loaded costs savings of $450,000 for the three positions.

As a result the cost benefit analysis shows total projected labor cost savings, inclusive of salary and employee benefits, of $900,000 per year.

Q. WHAT ADJUSTMENT TO LABOR COSTS DO YOU RECOMMEND IN THIS CASE ASSOCIATED WITH THE IMPLEMENTATION OF THIS NEW SYSTEM?

A. As the Company has included this significant plant cost and rate base associated with this new system, the offsetting savings should also be reflected. On Exhibit OCS 3.16, I reflect the labor cost reduction of $900,000. Again, this adjustment is based on the projections included by the Company in its cost benefit analysis associated with the project and would include payroll as well as employee benefit costs associated with these positions. As shown on Exhibit OCS 3.16, the total projected labor cost savings of $900,000 results in a reduction to O&M expense of $623,218 on a total Company basis and $260,964 on a Utah basis.

<u>Incentive Compensation Expense</u>

Q. WHAT AMOUNT HAS THE COMPANY INCLUDED IN THE PROJECTED TEST YEAR FOR INCENTIVE COMPENSATION COSTS AND HOW DOES THAT COMPARE TO ACTUAL RECENT COSTS INCURRED BY THE COMPANY?

A. RMP included $33,719,000 of projected annual incentive plan costs in the future test year ending June 30, 2012. This amount is based on the average of the Company budgeted 2011 and budgeted 2012 incentive plan costs at the target payout level. The actual cost recorded by the Company for annual incentive plan for the base year ended June 30, 2010 was $26,335,244; thus, the Company is proposing to increase incentive plan costs by approximately $7.4 million in its filing.

The $33.7 million incorporated in the Company's request is significantly higher than the actual amounts recorded in the past several years. According to the Company's response to DPU 22.14, the total actual incentive compensation for the 2009 AIP plan year was $28,666,705 and the total amount for the 2010 plan year was $28,603,926. During those same two years, the total target incentive compensation assuming 100% payment was $37.7 million and $32.0 million, respectively. In each of those two years the Company did not pay at the target level that it had projected.

In the Company's prior rate case, Docket No. 09-035-23, the Company projected annual incentive compensation expense at the target level for the test year in that case, which is the twelve months ended June 30, 2010, of $32,526,352. However, based on the Company's filing in the current case, the actual incentive compensation plan costs for that same twelve month period was only $26,335,244. In other words, the actual cost was $6.19 million less than the Company had projected for the same time period in the prior rate case.

Q. WHAT FACTORS HAVE CAUSED THE COMPANY'S ANNUAL INCENTIVE PLAN COSTS TO BE SO MUCH LOWER THAN THE TARGETED LEVELS AND THE PROJECTED AMOUNTS?

A. In response to OCS 6.4, RMP indicated that it projected in the prior case that the budgeted full-time equivalent positions would be filled in the future test period and that 100% payout of incentives would be made at the target level. The response to OCS 6.4, indicates that the actual incentive plan payouts in calendar years 2009 and 2010 were less than had been projected and less than the historic payout percentage as a result of the Company not filling its budgeted full-time equivalent positions, failure to meet Corporate safety goals, and "Some employees failed to have satisfactory performance regarding individual and group goals, including safety."

Q. ARE THERE ANY FACTORS THAT WOULD INDICATE THAT THE BUDGETED INCENTIVE COMPENSATION COSTS INCORPORATED BY THE COMPANY FOR ITS FUTURE TEST YEAR ENDING JUNE 2012 ARE OVERSTATED?

A. Yes. As previously indicated, the Company's projected amounts incorporated in the case are based on the average of the 2011 and 2012 budgeted amounts. Thus, these budgeted amounts would assume that all budgeted positions at the Company are filled. In other words, the amounts are not based on the employee complement that is incorporated in the Company's case, which are based on the base year employee compliment, but is based on the higher total employee complement that the Company uses for budgeting purposes for years 2011 and 2012. Historically, the actual employee complement at PacifiCorp has been significantly less than the amount budgeted.

*****BEGIN CONFIDENTIAL***** [redacted]*****END CONFIDENTIAL***** It is not reasonable or appropriate to incorporate incentive compensation costs in this case at a level that would assume all of the Company's budgeted positions will be filled.

Q. WHAT AMOUNT DO YOU RECOMMEND BE INCORPORATED IN THIS CASE FOR THE ANNUAL INCENTIVE PLAN COSTS?

A. As shown on Exhibit OCS 3.17, I recommend that the annual incentive plan costs for the future test year ending June 30, 2012 be set at $29,536,612. As shown on the exhibit, this amount is calculated as the average of the actual 2009 and actual 2010 incentive compensation escalated for the January 2011 labor escalation for non-union employees factored into the Company's filing, as well as 50% of the projected January 2012 labor escalation rate for the impact of the 2012 increase that falls into the test year ending June 30, 2012. This would allow for incentive compensation expense based on the average of the last two calendar years available and an escalation for labor increases that would occur during 2011 and 2012 that would impact the future test year. As shown on the exhibit, my recommendation is that the Company's proposed incentive compensation expense be reduced by $4,182,388, thereby reducing the incentive compensation expenses by $2,896,157. The reduction on a Utah basis is $1,212,727.

The Company has provided no information to support costs above this recent historic level.

<u>Pension Expense</u>

Q. WHAT AMOUNT DID THE COMPANY RECORD DURING THE BASE YEAR ENDED JUNE 30, 2010 FOR PENSION COSTS AND HOW DOES THAT COMPARE TO THE COST FOR THE YEAR ENDED DECEMBER 31, 2010?

A. The base year pension costs, on a gross basis (prior to removal of the joint venture portion), was $31,668,304. The actual pension for the year ended December 31, 2010 was $30,723,502[2], which is approximately $944,000 less than the amount for the base period ended June 2010.

Q. WHAT AMOUNT DID THE COMPANY INCLUDE IN THE PROJECTED TEST YEAR ENDING JUNE 30, 2012 FOR PENSION EXPENSE?

A. Company Exhibit RMP__(SRM-3), page 4.16.7, shows budgeted pension expense for the 12 months ended June 2012 on a gross basis, at $41.65 million and $40,207,167 on a net of joint venture basis. It is the net of joint venture basis of approximately $40.2 million that flows through the Company's revenue requirement request in this case.

Based on the response to R746-700-200.C.3.f, the projected test year cost was calculated by utilizing 50% of the projected 2011 defined benefit pension plan costs of $27.4 million and 50% of the projected 2012 costs of

[2]December 31, 2010 ROO, page 4.3.7.

$28.2 million, resulting in an average amount of $27.8 million. RMP added $13.85 million to the $27.8 million projected defined benefit pension plan costs for its projected payments to the Local 57 retirement trust fund, resulting in the total requested amount of $41.65 million on a gross basis. The payments to the Local 57 trust fund were projected by RMP at the time it prepared the filing to be $8.9 million in calendar year 2011 and $18.8 million in calendar year 2012, and the $13.85 million included in the Company's request is the average of these two amounts. As the Local 57 retirement plan is a joint trustee plan, the Local 57 pension cost recorded on RMP's books equals the amount contributed to the plan, and the amount contributed is determined through collective bargaining negotiation.

Q. WHEN WERE THE PENSION EXPENSE PROJECTIONS INCORPORATED IN THE COMPANY'S FILING PREPARED?

A. The projections are based on a 10-Year Expense and Funding Projection prepared by the Company's actuarial firm, Hewitt. The calculations were based on the preliminary January 1, 2010 actuarial valuation results which were updated on September 23, 2010. In the 10-year pension expense projections that were updated on September 23, 2010, provided in response to DPU 5.8, the Company changed several of its key assumptions in forecasting the pension expense from those selected for the 2010 plan year. The key assumptions in the document show that the

Company reduced the discount rate used in projecting the pension costs from 5.8% in 2010 to 5% for the years 2011 through 2020. The response also shows that the Company reduced the long-term rate of return on asset assumption in its 10-year projection from 7.75% to 7.5% beginning in 2011. Each of these changes would have a significant impact on the projected cost levels, causing the forecasted costs to be higher. Additionally, as the projections were prepared in September of 2010, the impacts of the actual 2010 pension plan experience would not be reflected in those projections. Thus, the projections would not reflect the impact of any actuarial gains that occurred in 2010.

Q. WAS THE COMPANY ASKED TO PROVIDE UPDATED ACTUARIAL PROJECTIONS IN THIS CASE?

A. Yes, it was. The Company was required to select the actuarial assumptions for use in the 2011 pension plan year by December 31, 2010, and the actual experience of the pension plan and the return earned on the pension plan assets during 2010 are now known. Therefore, the Company was asked in OCS 6.9 to provide the revised amount of pension expense that would result for the test year ending June 2012 if the actuarial assumptions selected by the Company for the 2011 plan year were incorporated. The question also asked the Company to update the projections to incorporate the impact of the actual 2010 pension plan experience and the plan asset value at the end of 2010, as well as the impact of the current assumptions regarding the amount of cash contributions to be made to the pension plan in 2011 and 2012.

In response, RMP indicated that "The following are available to the Company since they are product of current accounting disclosure and measurement requirements." The Company indicated that the projected PacifiCorp retirement plan 2011 expense is currently $24 million and that the Local 57 retirement trust fund expense for the period January 1, 2011 through June 30, 2011 is $6.4 million. The response also indicated that: "At this time, the Company does not have revised estimate of plan expense for the periods after December 31, 2011 for the PacifiCorp retirement plan." The Company also indicated that they project a significant increase in Local 57 expense after June 30, 2011, but did not provide any further information or details regarding the purported projected increase. Unfortunately, the Company did not provide all the information requested. It specifically did not provide an updated estimate of the projected pension expense for the year ended December 31, 2012 or for the test period in this case. There was no indication in the response as to why the Company did not ask its actuarial firm to provide these updated projections.

Q. HOW DO THE LIMITED PROJECTIONS THE COMPANY PROVIDED COMPARE TO THE AMOUNT INCLUDED IN THE COMPANY'S CASE?

A. The Company's current projection of the PacifiCorp retirement plan cost for 2011 is $24 million. As previously mentioned the Company had projected the cost to be $27.4 million in 2011 in preparing its filing. Thus, the projected costs have declined based on the actuarial assumptions actually selected by the Company for 2011 coupled with the actual pension plan experience for 2010. While the Company has not provided a revised projection of the 2012 pension plan cost, it is clear that the amount incorporated in its filing of $28.2 million is overstated. It does not reflect the updated actuarial assumptions, nor does it reflect the actual 2010 pension plan expense and the gain on the pension plan assets that occurred in 2010.

Q. DID THE PENSION PLAN ASSETS EARN MORE DURING 2010 THAN WHAT WAS ORIGINALLY PROJECTED BY THE COMPANY?

A. Yes. The Company's 2010 actuarial projections incorporated an assumed long-term rate of return on plan assets of 7.75%. However, based on the Company's response to OCS 6.14, the actual return on the pension plan assets was 12.18% in that period; thus, the return exceeded the long-term rate of return assumption incorporated in the plan projections. This impacts the calculation of pension expense for all years thereafter as the plan asset balance at December 31, 2010 would be higher than originally projected.

Q. DO YOU RECOMMEND ANY ADJUSTMENTS TO THE PENSION EXPENSE INCORPORATED IN THE COMPANY'S FILING?

A. Yes, I recommend the amount included in the filing be reduced. The amount incorporated in the filing is based on outdated projections, is overstated, and does not reflect current conditions or the actual experience of the 2010 pension plan assets. Since the Company did not have its actuarial firm prepare updated projections regarding the 2012 pension expense, I recommend that the recent projections provided for the 2011 pension plan costs be used as a starting point in projecting the pension expense to include in the test year. Additionally, I am recommending a few modifications to that amount to reflect a more reasonable and appropriate long term rate of return assumption.

My recommended adjustment to pension expense is presented on Exhibit OCS 3.18. As shown on this exhibit I recommend that the test year pension costs be set at $34.3 million on a gross basis and $33,111,779 on a net of joint venture basis. This is $7,095,388 less than the $40,207,167 incorporated in the Company's filing. After application of the expense factor used by RMP in its filing of 69.25%, my adjustment results in a reduction in test year employee benefit expenses of $4,913,308 on a total Company basis, or $2,057,382 on a Utah basis.

Q. WOULD YOU PLEASE DISCUSS YOUR RECOMMENDATION FOR THE AMOUNT TO INCLUDE FOR THE PACIFICORP RETIREMENT PLAN 2011 EXPENSE?

A. Yes. As shown on Exhibit OCS 3.18, I first reflect the Company's updated projection of the 2011 retirement plan cost of $24 million. As this is the most recent actuarial projections provided by the Company, this is the best information available for purposes of projecting the test year pension expense in this case. Since the Company did not provide updated projections for the 2012 pension plan year; the 2011 expense level is the only projection available. The projected 2012 pension plan cost is known to be incorrect because it does not include the impact of the 2010 pension plan performance or the more recent actuarial assumptions. In fact, it incorporates a discount rate of 5.00% which is much lower than the amount used by the Company in its 2010 and its 2011 actuarial projections.

Additionally, for purposes of projecting the test year pension plan costs, I recommend that the impact of 25 basis point increase in the long term rate of return of assumption reflected. It is my opinion that the long term rate of return assumption used by the Company in its recent 2011 pension plan projection is understated and artificially inflates the pension plan expense.

Q. WHAT LONG TERM RATE OF RETURN ASSUMPTION WAS USED BY THE COMPANY FOR PURPOSES OF DETERMINING ITS UPDATED 2011 PENSION PLAN COST PROJECTION?

A. The Company provided the actuarial assumptions that were selected at the end of 2010 for the 2011 plan year in its confidential response to OCS Data Request 6.7. For the Company's 2010 pension plan, the actuarial calculations incorporated a discount rate of 5.80%, an expected long-term rate of return on plan assets of 7.75%, and a salary increase rate of 3.0%. The Company has used the 7.75% long term rate of return assumption in its actuarial projections for each of the past three years, 2008 through 2010. In 2007 the long-term rate of return assumption adopted by the Company was 8%, and it was 8.5% for the period from April 1, 2006 through December 31, 2006.

*****BEGIN CONFIDENTIAL***** [redacted]. [redacted] *****END CONFIDENTIAL*****

I do not take issue with the change in the discount rate that occurred between 2010 and 2011 as there is much less flexibility available to companies regarding the selection of what discount rate to use in the actuarial projections as compared to other assumptions. However, I do recommend that the long term rate of return on asset assumption be increased by 25 basis points to reflect a more appropriate and reasonable projection on a going forward basis.

Q. HOW HAS THE LONG TERM RATE OF RETURN ASSUMPTION SELECTED BY THE COMPANY IN PREPARING ITS ACTUARIAL PROJECTION COMPARED TO THE ACTUAL RETURN ON THE PENSION PLAN ASSETS FOR EACH OF THE LAST FIVE YEARS?

A. The table below presents, by year, the actual return on pension plan assets achieved by the Company as compared to the long term rate of return assumption used in the actuarial projections.

Year	Long Term ROR Assumption	Actual Return
2006	8.75%/8.5%	12.04%
2007	8.00%	8.97%
2008	7.75%	-23.26%
2009	7.75%	22.96%
2010	7.75%	12.18%

While one would not base the long term rate of return assumption on a short history of the actual return on pension plan assets, it is something that should at least be considered in evaluating what long term rate of return assumption should be used on a going forward basis and whether or not to revise the assumption. It is one of many factors that are considered in setting the rate going forward as the assumed rate of return on plan assets incorporated in actuarial calculations is a long-term assumption.

Q. HOW DO THE LONG TERM RATE OF RETURN ASSUMPTIONS SELECTED BY PACIFICORP FOR PURPOSES OF PROJECTING ITS PENSION COSTS IN THE ACTUARIAL CALCULATIONS COMPARE TO THAT OF OTHER COMPANIES?

A. The long term rate of return assumption that has been used by PacifiCorp is at the low end of the range as compared to other companies. OCS 21.7 asked the Company to provide any industry survey or industry study data completed within the past two years that is in its possession which shows the actuarial assumption being used by other companies and by other utilities. In response, RMP provided the 2009 Hewitt FAS 87/106 survey results. Page 3 of the attachment to the Company's response provides Hewitt's survey results for the long-term rate of return used by companies for 2009. The response indicates that there were 107 respondents to the survey and 5.6% of the participants selected a long term rate of return assumption for 2009 that was in the range of 7.75% to 7.99%. PacifiCorp was within this range in both 2009 and 2010, using a 7.75% assumption. The survey shows that 29.9% of the respondents utilized a long-term rate of return assumption of 7.99% or less and the remaining respondents, or 70.1% used a long-term rate of return for 2009 of 8% or above. The survey also shows that 75.5% of all respondents used a long-term rate of return assumption of 7.75% or higher in their actuarial projections. Clearly, PacifiCorp is at the low end of the range when it comes to the long-term rate of return assumption used in its actuarial projections. The lower the long term rate of return assumption selected, the higher the pension expense that results.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND BE MADE TO THE PENSION EXPENSE ASSOCIATED WITH THE LONG TERM RATE OF RETURN ASSUMPTION?

A. I recommend that a 25 basis point increase in the assumption selected by the Company for 2011 be incorporated in projecting the pension expense for the test year in this case. In response to OCS Data Request 21.4, the Company indicated that a 25 basis point increase in the long-term rate of return assumption used in the actuarial calculations for the PacifiCorp retirement plan 2011 expense would decrease that expense from $24 million to $21.5 million, or a reduction of $2.5 million. As shown on Exhibit OCS 3.18, I have reflected this $2.5 million reduction for purposes of projecting the pension cost to incorporate in the test year ended June 30, 2012 in this case. *****BEGIN CONFIDENTIAL***** [redacted]

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

Q. PLEASE DISCUSS THE AMOUNT THAT YOU RECOMMEND BE INCLUDED IN THE PENSION COSTS FOR THE LOCAL 57 RETIREMENT TRUST FUND CONTRIBUTIONS.

A. In projecting the amount included in its filing, RMP projected the contribution at $8.9 million in calendar year 2011 and $18.8 million in calendar year 2012, resulting in its proposed test year contribution of $13.85 million. As previously indicated, in response to OCS 6.9 RMP indicated that the Local 57 retirement trust fund contribution for the period January 1, 2011 through June 30, 2011 is projected to be $6.4 million. However, the Company did not provide updated estimates for expenses beyond June 30, 2011 associated with the Local 57 plan. In response to OCS 6.9, RMP indicated that the final expense for the period subsequent to June 30, 2011 would depend on several factors, including demographic experience and asset return for the period January 1, 2011 through June 30, 2011. As the amount present by the Company in the response to OCS 6.9 is for a six month period, I recommend that the $6.4 million for that period be doubled to reflect an annualized level which would allow for an annual expense of $12.8 million.

According to the Company's 2010 Form 10-K, the contribution to the Joint Trust Union plan made by PacifiCorp was $13 million per year for each of the years ended December 31, 2008 through December 31, 2010. Thus, my recommendation is consistent with the actual cost that was incurred for each of the last three years. As the Company has provided no support or justification for projections above this amount, I recommend the $12.8 million be used for the test year.

Q. WHAT IS THE OVERALL IMPACT OF YOUR PENSION COST RECOMMENDATIONS?

A. As shown on Exhibit OCS 3.18, the combination or sum of my recommended revisions to the pension cost projections result in a test year pension cost of $34.3 million on a gross basis. The result is a $4,913,308 reduction to pension expense and a $2,057,382 reduction on a Utah basis.

<u>Uncollectible Expense</u>

Q. HOW DID THE COMPANY CALCULATE THE UNCOLLECTIBLE EXPENSE INCORPORATED IN ITS FILING?

A. In calculating the projected uncollectible expense for the test year, the Company began with the Utah situs uncollectible expense recorded on its books during the base year of $4,709,966. It then divided that amount by the unadjusted Utah General Business Revenues, resulting in a proposed uncollectible rate of 0.315%. RMP then applied the uncollectible rate of 0.315% to its forecasted test year normalized Utah General Business Revenues of $1,702,237,831, resulting in a forecasted uncollectible expense incorporated in its filing of $5,356,171 on a Utah situs basis.

Q. ARE YOU RECOMMENDING ANY REVISIONS TO THE COMPANY'S FORECASTED UNCOLLECTIBLE EXPENSE IN THIS CASE?

A. Yes, I am. I recommend that the forecasted uncollectible expense for Utah be recalculated based on the Company's target uncollectible rate of 0.27%. The uncollectible rate used by the Company in its filing is inconsistent with the historic average of net write-offs to revenues and it is inconsistent with the Company's uncollectible target rate.

In response to DPU Data Request 18.5, the Company indicated that a plan was developed in 2009 to reduce uncollectibles and that the plan was modified in both 2010 and 2011. The response indicates that "The plan covers four areas: increase efforts to help customers reduce and manage their bills, increase efforts to help customers obtain financial assistance, obtain deposits from at-risk customers and utilize targeted field collections." The Company also indicated that the plan has been successful in managing the uncollectibles. As the Company has a target rate and has taken steps to improve its collections to achieve that target rate, I recommend that target rate of 0.27% of Utah retail revenue be used in forecasting uncollectible expense in this case.

Q. IN THE COMPANY'S PRIOR RATE CASE, DOCKET NO. 09-035-23, DPU WITNESS BRENDA SALTER RECOMMENDED THAT UNCOLLECTIBLE EXPENSE BE CALCULATED BASED ON A THREE-YEAR AVERAGE OF NET WRITE-OFFS TO UTAH RETAIL REVENUES WITH THE RESULTING RATE BEING APPLIED TO UTAH RETAIL REVENUES. IS THAT A REASONABLE APPROACH FOR PURPOSES OF SETTING UNCOLLECTIBLE EXPENSE IN A FORECAST TEST PERIOD?

A. Yes, it is. In fact, in many cases I have recommended that uncollectible expense be based on a historic average of net write-offs to revenues, typically recommending a historic period of three to five years in setting the rate. It is appropriate to set uncollectibles on a historic percentage of net write-offs to revenues because the level of uncollectible expense as compared to revenues tends to fluctuate from year-to-year and using a historic average smoothes the variances between periods resulting in a reasonable projection of expense on a going forward basis.

Q. HAVE YOU CALCULATED THE AVERAGE UNCOLLECTIBLE RATE?

A. Yes. On Exhibit OCS 3.19, page 3.19.1, I show the amount of net write-offs compared to retail sales revenues for the three years ending June

2008, June 2009 and June 2010 and the period July 2010 through March 2011. As shown on page 3.19.1, the percentage of net write-offs to revenues has ranged from a rate of 0.2304% for the period July 2010 through March 2011, or the most recent period available, to a rate of 0.3492% for the year ended June 2009, which is the year immediately prior to the base year in this case. As shown on this page, the average percentage net write-offs to revenue using the years ended June 2008, June 2009, June 2010 and the period July 2010 through March 2011, results in an average percentage of net write-offs to revenues of 0.2879%. Additionally, it shows that the percentage of net write-offs to revenues for the most recent period available is 0.2304%.

This information further supports my recommendation that rates be set using the target rate of 0.27%.

Q. WHAT ADJUSTMENT SHOULD BE MADE TO REFLECT YOUR RECOMMENDED RATE OF 0.27%?

A. Applying the target uncollectible rate for RMP of 0.27% to the Company's normalized Utah General Business Revenues of $1,702,237,831 results in a forecasted test year uncollectible expense of $4,596,042. As shown on Exhibit OCS 3.19, this is $760,129 less than the amount proposed by the Company. Thus, test year uncollectible expense should be reduced by

$760,129. As the uncollectible expense is determined on a Utah situs basis, this full reduction is applicable to the Utah jurisdiction.

<u>Remove Company Rent Contributions</u>

Q. WHAT HAS THE COMPANY INCLUDED IN THIS CASE FOR CONTRIBUTION OF RENT EXPENSE OR OFFICE SPACE?

A. The Company provides subsidized sub-leases to the Economic Development Corporation of Utah ("EDCU") and the Utah Sports Authority for office space in One Utah Center. The Company sub-lets the office space for $1 per month rent plus operating expenses to each of these entities. In this case, RMP included the full rent cost above the line resulting in RMP's ratepayers subsidizing this office space. Base year costs include $100,000 associated with the EDCU rent contribution and $57,072 for the Utah Sports Authority rent contribution. These base year costs were escalated in the Company's filing, resulting in test year expenses for these two items of $163,182.

Q. HAS THE COMMISSION ALLOWED THESE COSTS IN PAST CASES?

A. No, it has not. In its Report and Order in Docket No. 09-035-23, the Commission specifically disallowed these costs. While acknowledging at page 94 of the Decision its concurrence with the Company that economic development activities are important to the state, the Commission nonethe-less disallowed these costs for recovery from ratepayers. The Decision stated that these costs were removed in Docket Nos. 07-035-93 and 08-035-38.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the rent contribution be disallowed. These equate to in-kind charitable contributions of free office space to organizations that are effectively being subsidized by the Company's captive ratepayers. RMP's ratepayers should not be forced to pay these contributions through their utility rates. RMP has provided no new evidence in this case beyond what has been presented to the Commission in prior cases that would cause the Commission or parties to change their position on this issue. As shown on Exhibit OCS 3.20, test year expenses should be reduced by $163,182 to remove these rental contributions.

<u>Outside Services and Miscellaneous Expenses</u>

Q. WHAT AMOUNT HAS RMP INCLUDED IN THE ADJUSTED TEST YEAR FOR OUTSIDE SERVICES EXPENSE RECORDED IN FERC ACCOUNT 923?

A. The base year expense recorded by the Company in Account 923 was $10,882,652. Three of the Company's adjustments presented in Exhibit RMP_(SRM-3) impacted the amount recorded in FERC 923, increasing the amount by $1,736,634. This resulted in the projected test period expense in Account 923 of $12,783,372. Adjustments made by the Company to the base year level included an increase of approximately $1.2 million to reverse some non-recurring entries that were recorded during the base year, an increase of approximately $545,000 associated with its application of an escalation factor to the Account 923 expenses, and a slight reduction of approximately $4,000 reflected in its wage and employee benefit adjustment.

Q. SHOULD ANY ADDITIONAL ADJUSTMENTS BE MADE TO THE OUTSIDE SERVICES EXPENSE RECORDED IN FERC ACCOUNT 923 BEYOND THOSE ALREADY REFLECTED BY THE COMPANY IN ITS FILING?

A. Yes. Several additional costs recorded in the base year need to be removed. On Exhibit OCS 3.21 page 3.21.1, I provide a listing of additional outside service expenses that were recorded during the base period which I recommend be removed. The list shown on page 3.21.1 provides the base year amount as well as the escalation factor applied by the Company, and shows the total amount reflected in the Company's adjusted test year for each of the items that I recommend for removal. For several of the items listed, RMP has agreed in response to discovery that the amounts should be removed from the test year in this case; however, for several additional costs the Company has not agreed with the removal.

As shown on page 3.21.1, I recommend that test year expenses in FERC Account 923 – Outside Services be reduced by an additional $931,971 on a total Company basis.

Q. WOULD YOU PLEASE DISCUSS THE OUTSIDE SERVICE COSTS THAT THE COMPANY AGREES SHOULD BE REMOVED AND IDENTIFY WHY THOSE COSTS SHOULD BE REMOVED?

A. The first four items shown on page 3.21.1 are costs that the Company has agreed in response to discovery should be removed from the test year. The first cost listed is for the services of Herbert Smith, LLP, which is a law firm specializing in international law. In response to OCS 23.4, RMP indicated that charges from Herbert Smith, LLP will be removed from the rate case in the Company's rebuttal filing. In that response, RMP also indicated that it would remove charges recorded during the base year from Willkie Farr and Gallagher, LLP. The escalated test year expenses should be reduced by $426,577 to remove the fees from Herbert Smith, LLP and by $25,674 to remove the fees from Willkie Farr and Gallagher, LLP.

During the base year the Company recorded $10,000 in Account 923 for charges from R&R Partners, Inc. with the escalated test year amount included in the filing being $10,443. In response to OCS Data Request 6.27(b), the Company indicated that R&R Partners, Inc. "…performed a study on the Company's effectiveness in providing information to the media and in responding to media stories about the Company." The OCS further inquired into these costs in OCS 23.2, seeking a more detailed description of the services provided by R&R Partners, Inc. as well as a copy of any contracts, engagement letters, or agreements between the Company and R&R Partners, Inc. The question also asked for a copy of any reports, memo, or studies provided by R&R Partners, Inc. to the Company as a result of the study that was performed in the engagement. In response to OCS Data Request 23.2, RMP merely responded: "The Company withdraws its request for recovery." On page 3.21.1 of Exhibit OCS 3.21, I reflect the removal of this cost from the test year in this case.

Based on the Company's response to R746-700-22.D33, $252,700 was recorded in Account 923 during the base year for charges from Potomac Economic LTD. On Company Exhibit RMP__(SRM-3), page 4.3.1, the Company removes $85,998 in the test year for charges from Potomac Economics LTD. The Company's filing indicates that these costs are associated with an audit for compliance and the submittal of quarterly reports to FERC associated with market monitoring audits required by FERC. The filing also indicates that the $85,998 was being removed because the Company expected that there would not be any future payments to Potomac Economics for these services as PacifiCorp was released from this FERC requirement in April 2010. OCS 23.6 inquired why the remaining costs recorded in the test year for charges from

Potomac Economic LTD were not also removed in the Company's adjustment. In response, RMP stated that: "It was the Company's intent to remove all costs associated with market monitoring audit costs provided by Potomac Economics included in the base period." The response also indicated that the Company would update its request to remove the additional $166,702 from Account 923 that was in the base period, and that the escalated amount in the test year to be removed is $174,087. Thus, on page 3.21.1, I am removing the remaining balance in the test year for charges from Potomac Economic LTD.

Q. PLEASE DISCUSS THE REMAINING OUTSIDE SERVICES EXPENSES THAT YOU RECOMMEND BE REMOVED FROM THE TEST YEAR IN THIS CASE.

A. First, I recommend that expenses included in the adjusted test year from Protiviti, Inc. be removed, reducing base year expenses by $94,000 and adjusted test year expenses by $98,164 after the application of the 4.43% escalation factor. In response to OCS 23.5, the Company provided a description of the services provided by Protiviti, Inc. during the base period. The costs were for professional services associated with 2009 California and Oregon compliance audits. For California, Protiviti was retained by the Company to perform an independent third party audit of compliance with the California affiliate transaction rules that are required by the California Public Utility Commission. For the Oregon services, Protiviti, Inc. prepared an independent third party report that was required by OAR 860-038-0640 to verify the Company’s compliance with code of conduct rules for direct access. I recommend that these costs be removed from the test year as the services were specific to requirements in the states of California and Oregon and should be charged directly to those states. Thus, the adjusted test year expenses should be reduced by $98,164 to remove these costs.

During the base period the Company also recorded several charges in Account 923 from Tegarden & Associates, Inc. associated with appraisal services. $44,587 of the costs recorded in the test year from this vendor was for Tegarden & Associates, Inc.’s preparation of an appraisal of the Company’s utility operating property as of January 1, 2008 associated with an appeal of the assessed value assigned to the Idaho operating property by the Idaho State Tax Commission. Based on the invoice for these fees, dated June 22, 2009, provided by the Company in response to OCS Data Request 6.27, these charges were incurred prior to the start of the base period in this case. These are out of period costs that were incurred by the Company prior to the base period in this case and should be removed.

Base year expenses also include $52,599 from Tegarden & Associates related to the preparation of two appraisals of the Company’s utility operating property in the State of Montana as of January 1, 2006 and

January 1, 2007. According to the response to OCS 6.27, the appraisals, were prepared for and submitted in connection with an appeal of the assessed values assigned to the Company's Montana operating property by the Montana Department of Revenue. I recommend that these costs, which are non-recurring in nature and associated with appraisal values as of 2006 and 2007 be removed from the test year in this case. The total amount included in the escalated test year for the invoices from Tegarden & Associates, Inc. that I recommend for removal is $46,562 and $54,929, respectively.

In its Miscellaneous Expense adjustment, RMP removed several costs associated with the Centennial Celebration. However, base year expenses recorded in Account 923 included $19,310 for payments to ISite Design for a Centennial History Website which was not removed in the Company's adjustment. I recommend that test year expenses be reduced by $20,165 to remove the escalated costs associated with the Centennial Website design.

Q. PLEASE DISCUSS THE NEXT ITEM ON YOUR LIST OF OUTSIDE SERVICES EXPENSE FOR REMOVAL, SHOWN AS CHARGES FROM PARANDCO, LLC.

A. During the base year in this case, the Company recorded $72,000 in FERC Account 923 for charges from Parandco, LLC. After escalation, the amount included in the adjusted test year is $75,190. OCS Data Request 6.27(a) asked the Company to describe what services were provided by Parandco, LLC during the base year and for a copy of the associated invoices. In response the Company indicated that: “Parandco, LLC provided business consulting services in support of the development of a long-term energy plan by the State of Utah.” The Company also provided copies of the invoices during the base period as part of its response. The invoices provided include no detail whatsoever and merely state “Charges for Services Rendered” showing the amount of $12,000 per month. The invoices show no description of the services that were rendered by Parandco on behalf of PacifiCorp.

OCS Data Request 23.1 requested additional detail regarding the services provided by Parandco, LLC and also requested copies of contracts between the Company and Parandco. In response to the sub-part of the request seeking a more detailed description of the services provided, the Company referred to the consulting services agreement that it provided as an attachment to the response. The January 26, 2010 consulting services agreement with Parandco, LLC provided the following scope of work:

Exhibit A
Statement of Work

1. Consultant shall assist Rocky Mountain Power with the development of a regulatory strategic plan that would support the long term energy policies and objectives of the State of Utah. In conjunction with this activity, the Consultant will:

Redacted

> a. Advise and opine on critical business, regulatory and community issues and obstacles and assist with solution development;
> b. Enhance access to the Governor's administration and facilitate discussions between government officials, appropriate business contacts and Rocky Mountain Power;
> c. Create influencing opportunities for Rocky Mountain Power executives with key business community leaders to educate and inform them of key energy issues that impact Utah's energy future.
>
> 2. Consultant shall provide assistance and advise on any legislative strategies or individual legislative bills as requested by Rocky Mountain Power. Consultant is not being retained to lobby legislators on any specific legislative bill.
> 3. Consultant will provide assistance to state officials on energy related matters as requested by the state and as approved and directed by the Company.
> 4. Consultant will provide weekly progress updates to the Vice President of Regulation or Senior Vice President and General Counsel at Rocky Mountain Power to provide a status report on emerging issues and discussions that have taken place with business, government, or community leaders.

Under the contract, the Company agreed to pay the consultant, Stan Parrish of Parandco, LLC, $12,000 per month for the term of the agreement plus the reimbursement of any out of pocket expenses. Based on the information provided by the Company in response to OCS Data Request 23.1, the contract, which provides for monthly payments of $12,000, has been extended several times with the current expiration date shown as April 11, 2011. I recommend that all costs included in the test year associated with the payments to Parandco, LLC be removed, resulting in a reduction to the escalated test year expenses of $75,190.

Q. WHY DO YOU RECOMMEND THESE COSTS BE REMOVED?

A. First, the contract has expired. Second, and more importantly, it is my opinion that the services provided by Mr. Parrish to RMP under this contract should not be passed onto the Company's Utah ratepayers. The statement of work of services to be provided by Mr. Parrish, which was quoted previously in this testimony, are more lobbying and legislative in nature. Ratepayers should not be required to pay for a consultant to enhance the Company's access to the Governor's administration or to aid the Company in facilitating discussions between the Company and government officials. Costs associated with assisting and advising the Company on legislative strategies or individual legislative bills should be recorded below the line.

Q. ARE THERE ANY ADDITIONAL MISCELLANEOUS EXPENSES THAT YOU RECOMMEND BE REMOVED?

A. Yes. I am also recommending the removal of some costs recorded by the Company in FERC Account 930 – Miscellaneous General Expenses. As shown on OCS Exhibit 3.21, page 3.21.1, I am recommending that costs included in the escalated test year of $19,739, which were paid to the Utah Jazz be removed. The Company's ratepayers should not be required to fund the advertising and promotional costs that the Company chooses to pay to the Utah Jazz. Additionally, based on the associated invoices provided by RMP, the charges were incurred in April 2009, which is prior to the base year in this case. The information provided indicated that the payment was late, resulting in it being recorded during the base year.

I also removed $15,584 for the 2009 annual dues payment to the Utah Foundation. Based on invoices provided by the Company, the Company was late in paying the 2009 annual dues payment, resulting in base year expenses including dues for two years, 2009 and 2010. My recommended adjustment removes the escalated 2009 dues to ensure that two years worth of payments are not included in the test year.

Q. WHAT IS THE TOTAL AMOUNT OF ADJUSTMENT YOU ARE RECOMMENDING AT THIS TIME FOR OUTSIDE SERVICES EXPENSE AND MISCELLANEOUS GENERAL EXPENSES?

A. As shown on Exhibit OCS 3.21, I recommend that test year expenses be reduced by $967,114 on a total Company basis and by $414,882 on a Utah basis.

LINE LOSS FACTOR

Q. ARE YOU RECOMMENDING ANY REVISIONS TO THE LINE LOSS FACTORS PROJECTED BY THE COMPANY IN THIS CASE?

A. Yes. In determining the necessary gross up to test year sales for line losses, I recommend that a three-year average line loss factor by jurisdiction for the period 2008 through 2010 be used. In its filing, RMP uses a five-year average line loss factor that it applies to the test year forecasted energy sales to gross the sales up to test year energy requirements. RMP's five-year average is based on the years 2005 through 2009.

Q. WHY DO YOU RECOMMEND THIS ADJUSTMENT TO THE LINE LOSS FACTORS?

A. As shown in Exhibit OCS 3.23, page 1, the line losses for Utah has been declining since 2003. Pages 2 and 3 of Exhibit OCS 3.23 also show declines in line losses for Rocky Mountain Power and Pacific Power, respectively. When historic data shows a consistent downward trend, as seen for the Utah line losses, a moving average forecast will tend to overestimate the value being projected. The more years included in the moving average, the more dependent the forecast is on older data, which is not as reflective of current conditions. The fewer years in the moving average, the quicker the forecast responds to changes. A three-year average prediction will respond more quickly to changes in the line losses than will a five-year average.

Q. IS A THREE-YEAR AVERAGE LINE LOSS FACTOR METHODOLOGY MORE ACCURATE?

A. Based on recent past experience, yes. Exhibit OCS 3.24 shows a comparison of how the five-year moving average and three-year moving average methodologies would have performed in predicting line losses for 2005 through 2010 for Utah, RMP, and Pacific Power. In all three cases, the three-year average produces a more accurate forecast.

Q. WHY DO YOU USE 2010 AS PART OF YOUR THREE-YEAR AVERAGE RECOMMENDATION?

A. I recommend that a period that includes 2010 be used for several reasons. First, the 2010 actual sales and system loads are now available. Second, and more importantly, given the declining trends apparent in the loss factors, using 2008 through 2010 in determining the average line loss factor should provide a more accurate forecast of line losses than a forecast using 2007 through 2009.

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

A. Exhibit OCS 3.22 provides the impact on the energy requirements for Jurisdictional Allocation by using the more recent three year average. Total system energy requirements decrease by 54,915 MWh, or 0.1%. Utah energy requirements decrease by 160,363 MWh, or 0.6%.

Q. WHAT IMPACT DOES THE UPDATED LINE LOSS PROJECTIONS HAVE ON THE REVENUE REQUIREMENTS IN THIS CASE?

A. First, the reduction in system energy requirements reduces the power costs in this case. OCS witness Randall Falkenberg addresses the impact on net power costs in his testimony.

Second, the reduction in system energy requirements impacts the loads for jurisdictional allocation. This impacts the jurisdictional allocation factors that include system load in determining the allocation percentages between states. Since the Utah energy requirements are declining at a greater percentage than the system as a whole when comparing the more recent three-year average line loss factor to the factor used by the Company in its projections, the impact is a reduction in several of the jurisdictional allocation factors for the percentage allocated to the Utah jurisdiction.

Using the amounts presented in Exhibit OCS 3.22, I have reflected the revised loads for jurisdictional allocation in the Jurisdictional Allocation Model in this case. Thus, the revenue requirements presented by the OCS that result in Exhibit OCS 3.1 include the impact of the updated loads.

The information provided by the Company for energy sales and system load in response to OCS 4.4 included the Wyoming jurisdiction on a combined basis, whereas the JAM separates the Wyoming East and

Wyoming West jurisdictions in the model. Since the breakdown between Wyoming East and Wyoming West was not provided, I allocated the resulting Wyoming load presented on Exhibit OCS 3.22 of 10,731,273 MWH between the East and West jurisdiction based on the ratio of load between those two jurisdictions contained in the Company's JAM model.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes.