Witness CCS – 2D

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, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge	**)))))))))**	**Docket No. 07-035-93** **Pre-Filed Direct Testimony of Donna DeRonne For the Committee of Consumer Services**

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April 7, 2008

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INTRODUCTION

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

A. My name is Donna DeRonne. 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 PREVIOUSLY FILED TESTIMONY IN THESE PROCEEDINGS?

A. On January 25, 2008 I filed direct prefiled testimony on the issue of the appropriate test year in this docket. My qualifications were attached as Appendix I to that testimony and are not resubmitted here.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. Larkin & Associates, PLLC, was retained by the Utah Committee of Consumer Services (Committee) 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 to the Utah Public Service Commission (Commission) in the areas of rate base and operating income (expense and revenue). Accordingly, I am appearing on behalf of the Committee.

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

A. Yes. I have prepared Exhibits CCS 2.1 through 2.10, which are attached to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I present the overall revenue requirement recommended by the Committee and sponsor specific adjustments to the Company's filing for the future test year ending December 31, 2008. The overall revenue requirement presented in the summary schedules, specifically Exhibit CCS 2.1, includes the impact of recommendations of other witnesses testifying on behalf of the Committee. It includes the recommended return on equity and capital structure presented by Committee witness Daniel

Lawton, as well as specific adjustments recommended by Committee witnesses Randall Falkenberg, Philip Hayet and Helmuth Schultz.

Q. PLEASE DISCUSS HOW YOUR EXHIBITS ARE ORGANIZED.

A. Exhibit CCS 2.1, pages 1 through 39 presents the overall revenue requirement and summary schedules reflecting the impact of the Multi State Process (MSP) stipulation, which caps RMP's Utah revenue requirement at 101.25 percent of the Utah revenue requirement calculated under the rolled-in allocation method. Each of the pages in Exhibit CCS 2.1 is based on the rolled-in allocation method. Since the rates are capped at 101.25% of the rolled-in allocation methodology, I am not presenting an exhibit based on the MSP revised protocol jurisdictional allocation methodology (revised protocol method) with this testimony.

In preparing Exhibit CCS 2.1, I used the Company's Jurisdictional Allocation Model, flowing each of the Committee's recommended adjustments through the model.

Q. DO YOUR SUMMARY SCHEDULES INCLUDE THE EMBEDDED COST DIFFERENTIAL CALCULATION?

A. I have not included the Embedded Cost Differential calculation in my revenue requirement schedules presented with this testimony. The Embedded Cost Differential calculation does not impact the rolled-in allocation method and is only utilized in the revised protocol method.

Since the rates are capped at 101.25% of the rolled-in allocation method, the Embedded Cost Differential calculation does not, at this time, impact the rates of Utah customers. Thus, I did not incur the time and resources necessary to perform the calculation in this rate case.

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

A. Exhibit CCS 2.2 includes a summary schedule that lists all of the Committee's recommended adjustments in one schedule on a Utah basis. 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 CCS 2.1 as the amounts on this schedule are on the revised protocol method and do not include the cash working capital impact and interest synchronization impact of each of the adjustments as these impacts flow automatically through the jurisdictional allocation model.

The remaining exhibits attached to my testimony, Exhibits CCS 2.3 through 2.10, consist of the supporting calculations for the specific adjustments 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 CCS 2.2 through 2.10, the revised protocol jurisdictional allocations factors contained in Company Exhibit RMP__(SRM-1S) are used, consistent with how RMP's filing in Exhibit RMP__(SRM-1S) 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.

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

A. Rocky Mountain Power's revised filing shows a requested increase in revenue requirement of $123.4 million based on the revised protocol method, reduced to $99.8 million based on the 101.25% cap set forth in the MSP stipulation. Based on the Committee's analysis, the Company's request is significantly overstated by an amount of $91,368,238. As shown on Exhibit CCS 2.1, page 1, the Committee recommends an increase in the current level of Utah revenue requirement of $8,466,169.

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

A. I first present my recommended rate base adjustments, followed by recommended adjustments to net operating income.

RATE BASE ADJUSTMENTS

Q. WHAT ADJUSTMENTS TO RATE BASE DO YOU SPONSOR?

A. I am sponsoring adjustments to RMP's projected 2008 test year rate base for Powerdale decommissioning costs and cash working capital. I will discuss each of the adjustments below.

Powerdale Decommissioning Costs

Q. AS PART OF ITS SUPPLEMENTAL FILING, RMP MADE VARIOUS ADJUSTMENTS TO REFLECT THE IMPACT OF THE COMMISSION'S JANUARY 3, 2008 ORDER ON RMP'S REQUESTS FOR ACCOUNTING ORDERS. ARE YOU RECOMMENDING ANY REVISIONS TO THE AMOUNTS REFLECTED BY THE COMPANY WITH REGARDS TO THE COMMISSION'S JANUARY 3, 2008 FINDINGS?

A. I am recommending a revision to RMP's treatment of the Powerdale decommissioning costs. As part of its request in that docket, RMP sought permission to record its estimated Powerdale decommissioning costs in

Account 182.2 and to amortize the resulting deferral in rates at the time of the next rate case, which would be the present case. In that docket, the Committee agreed that it would be appropriate to record the estimated decommissioning costs in Account 182.2, thereby allowing the Company to avoid writing off the costs on its books. The Committee agreed that future recovery of the decommissioning costs, once incurred and known in amount, should be allowed. However, the Committee did not agree that the recovery of the estimated decommissioning costs from ratepayers should begin at the time of the next rate case proceeding, which is the current proceeding.

Q. PLEASE EXPLAIN THE REASONS THAT THE DECOMMISSIONING COSTS SHOULD NOT YET BE RECOVERED FROM UTAH RATEPAYERS.

A. According to RMP's application in Docket No. 07-035-14 and testimony filed by the Company in that docket, RMP may not incur decommissioning costs until April 2010. If the Company is permitted to include the projected decommissioning costs in rate base and include amortization of those projected costs in rates as part of the current rate case, the result would be that customers would begin paying for the decommissioning costs and a return on the decommissioning costs well in advance of the amounts actually being expended by RMP. Ratepayers should not be required to pre-pay these costs and to pay a return on these costs that have not yet been incurred. Rather, the Company should only begin to recover the costs after they are actually incurred. This would allow for recovery of actual costs instead of estimates and would allow for more certainty with regards to potential offsets to the decommissioning costs prior to the costs being included in rates. It would also avoid ratepayers paying a return to the Company on costs that have not been incurred.

Q. WHAT ARE SOME OF THE POTENTIAL OFFSETS TO THE PROJECTED DECOMMISSIONING COSTS?

A. The Company's analysis of the cost effectiveness of repairing and operating the facility versus retiring the facility included an assumption that the maximum estimated property insurance payment of $745,000 would be received. Any insurance proceeds received should be used to offset the decommissioning costs. Additionally, the Company may transfer the reusable Powerdale Plant assets to other Company hydro facilities at their net book value. There may also be a salvage value for equipment. The Company indicated in response to discovery in the accounting order docket that it will assign salvage rights to the removal contractor to offset the removal costs. To the best of my knowledge, the potential offsets for insurance, net salvage and other potential items have not yet been factored into the estimated decommissioning costs. Furthermore, in a 2003 settlement agreement pertaining to the operation and decommissioning of the Powerdale facility, the Company agreed to convey its interest in certain lands to a third party, and those lands have a value. If any proceeds from the sale of lands associated with the facility or surrounding area are received by RMP, those proceeds should also be used to offset the decommissioning costs. Finally, since the Company has agreed to convey certain lands to a third party, any tax benefit derived from the conveyance should also be used to offset the decommissioning costs.

In the event any proceeds are received after the unrecovered net plant costs and decommissioning costs are fully recovered, the amounts should still flow back to ratepayers. The Company should record any such proceeds as a regulatory liability on its books so that they may be addressed in future proceedings.

Q. DID THE COMMISSION RESOLVE THE ISSUE OF RECOVERY OF THE PROJECTED DECOMMISSIONING COSTS IN ITS JANUARY 3, 2008 REPORT AND ORDER IN DOCKET NO. 07-035-14?

A. No, it did not. The Commission's Order approved the Company's "…requested accounting for the Powerdale Plant, noting that our approval allows a change in accounting which is subject to future review and adjustment." (Page 18) The order allowed for the recording of the projected decommissioning costs as a regulatory asset in Account 182.2, but did not fully resolve the issue. The order specifically stated that Commission resolution of the parties' disputes could occur "…in some future proceeding where more and clearer evidence can be provided, whether continuing in Docket 07-035-14 or a future ratemaking proceeding." (Page 18) In fact, the order identified the concerns raised by the Committee with regards to potential offsets to decommissioning costs, including insurance proceeds, transferred equipment and real property and property tax issues, among others. The order specifically stated that the Commission did not resolve the specific disputes, indicating that the amounts are subject to review and possible adjustment in the future prior to their inclusion in a revenue requirement determination.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARDS TO THE POWERDALE DECOMMISSIONING COSTS?

A. It remains the Committee's position that ratepayers should not be responsible for funding the projected decommissioning costs until such time as they are actually incurred by RMP. The costs may not even begin to be incurred by RMP until 2010. There are too many uncertainties remaining regarding potential offsets to the decommissioning costs, such as insurance recoveries, salvage, potential land sales and tax benefits. While I agree that the regulatory asset should have been established for the projected decommissioning costs such that the Company would not be required to write-off the projected costs as an expense on its books, that regulatory asset should not yet be included in rate base and should not yet be recovered from Utah ratepayers. Clearly the regulatory asset associated with the projected decommissioning costs does not represent a cash outlay that has been made by RMP at this time; thus, RMP should not earn a return on this asset.

As shown on Exhibit CCS 2.3, I recommend that rate base be reduced by $5,974,107 on a total Company basis to remove the average unamortized balance included by RMP in regulatory assets, Account 182.2, in the projected test year. I also recommend that the amortization expense included by RMP for the regulatory asset of $1,211,786 (total Company) also be excluded from rates at this time. The Company should be allowed to continue to carry the regulatory asset on its books to acknowledge the fact that future recovery of the decommissioning costs is probable; however, a return should not be allowed on that non-cash balance as part of this case.

<u>Cash Working Capital</u>

Q. WHAT IS THE PURPOSE OF INCLUDING A CASH WORKING CAPITAL COMPONENT IN RATE BASE?

A. Cash working capital represents the investment that is needed to support the day to day cash operating costs of a Company. Cash working capital is determined as the difference between the utility's payment of current expenses and its receipt of revenues from serving customers. If the pay out of expenses occurs before the receipt of revenues from customers, there is a positive cash working capital need. Likewise, if the revenues, on average, are received from customers prior to the payment of expenditures, a negative cash working capital requirement exists. In many jurisdictions a lead/lag study is utilized to determine the cash working capital needs, or the net lead/lag days experienced by a utility. While one typically sees a positive cash working capital requirement, I have been involved in cases in which a utility is experiencing a negative cash working capital in which, on average, revenues are received prior to the payment of expenses.

Q. ARE YOU RECOMMENDING ANY REVISIONS TO THE CASH WORKING CAPITAL INCLUDED IN THE FILING?

A. Yes. I recommend that the cash working capital included in the filing be adjusted to include the impact of interest expense on long term debt. The Company's lead/lag study and cash working capital calculations did not include a component for long term debt. The costs to pay the interest expense on the long term debt are collected from the Company's customers in the revenues generated. The interest expense on long term debt is paid by the Company on a semi-annual basis. Between the time the Company receives revenues from its customers and the time it is required to make a disbursement of funds to pay the interest on the long term debt, the funds are available for use by the Company in its operations. Interest expense is typically a component in utility lead/lag studies and cash working capital calculations.

Q. WHAT IS THE AVERAGE INTEREST EXPENSE LAG ON LONG TERM DEBT?

A. The average expense lag, determined utilizing semi-annual interest payments, is 91.25 days. Using the Company's Utah revenue lag days in this case of 44.82 days results in net lag days interest expense lead days of 46.43 days.

Q. WHAT IS THE IMPACT OF REFLECTING THE INTEREST ON LONG TERM DEBT IN THE DETERMINATION OF CASH WORKING CAPITAL?

A. The impact is reflected on Exhibit CCS 2.4 and results in a $16.3 million reduction to rate base on a Utah basis. I have presented this exhibit to show the impact of the calculation. This adjustment must be separately input into the JAM model in the cash working capital section of the results as there currently is not a formula in the model to automatically include this impact.

Q. DO YOU HAVE ANY ADDITIONAL CONCERNS WITH THE COMPANY'S CASH WORKING CAPITAL REQUEST?

A. Yes. The Company is utilizing an outdated lead/lag study that most likely is no longer reflective of current circumstances. The study utilized by the Company was filed in May 2004 and was conducted based on information using the fiscal year ended March 31, 2003, with a few exceptions. PacifiCorp has undergone numerous changes in its structure and operations since that time. During that period, PacifiCorp would have become more fully integrated with ScottishPower, and then subsequently was acquired by MidAmerican. There have been numerous organizational changes since that time, along with changes in computer systems and billing structures. It is likely that the components of the lead/lag study that was conducted utilizing information for the period April 1, 2002 through March 31, 2003 is no longer reflective of current circumstances. Additionally, it is likely that the implementation of the Automated Meter Reading (AMR) system in Utah will reduce the revenue lag time as it should enable faster processing of bills and shorter meter reading times.

Q. GIVEN YOUR CONCERN THAT THE LEAD/LAG STUDY UTILIZED BY THE COMPANY IS OUTDATED, DID YOU PERFORM A SEPARATE LEAD/LAG STUDY IN THIS CASE?

A. No, I did not. Typically the Company performs an updated lead/lag analysis based on currently available information and the Committee reviews the study, including the calculations, assumptions and supporting documentation, for reasonableness. PacifiCorp has not performed such an update in the past several rate cases. I recommend that as part of the decision in this case, the Commission order the Company to file a new lead/lag study in its next rate case proceeding. Absent the filing of a new, updated study, the Company should not be allowed a cash working capital component in rate base in its next rate case as the amounts would not be supported by recent data.

<u>NET OPERATING INCOME</u>

<u>Pension and PBOP Expense</u>

Q. ARE YOU RECOMMENDING ANY REVISIONS TO THE PROJECTED TEST YEAR LEVEL OF PENSION AND POSTEMPLOYMENT BENEFITS OTHER THAN PENSIONS (PBOPs)?

A. Yes. I recommend that each of these retirement benefit costs be revised to reflect the impact of the actual plan experience in 2007. This should include the actual return achieved on the plan assets during 2007, reducing each due to favorable experience on the pension and PBOP plan assets as compared to the assumptions for 2007. These are known and measurable changes based on the actual 2007 experience for each of these respective plans.

In estimating the 2008 pension and PBOP costs for purposes of this rate case, the Company modified some of the actuarial assumptions from what was utilized in the prior year pension and PBOP cost determination. I am recommending a revision to the actuarial assumptions used in deriving the 2008 estimated costs to increase the projected long term rate of return on plan assets for both the pensions and PBOPs as compared to what was incorporated in the Company's filing. I recommend that the assumption for the long term rate of return on plan assets be increased by 0.25% or 25 basis points from that utilized by the Company in deriving its estimates.

Q. WHAT IS THE IMPACT ON THE PROJECTED 2008 PENSION AND PBOP COSTS RESULTING FROM THE PLAN RESULTS IN 2007?

A. In response to CCS Data Request 22.2, the Company indicated that the asset experience during 2007 was more favorable than what was incorporated in the actuarial assumptions, resulting in a $1.1 million decrease in the 2008 pension expense. Thus, at a minimum, the projected pension costs included in the Company's filing for the 2008 test year should be reduced by $1.1 million on a total Company basis.

In response to CCS Data Request 22.3, the Company also identified a more favorable asset experience than what was assumed during 2007, resulting in a $0.7 million reduction to projected 2008 PBOP expense. Thus, at a minimum, the projected PBOP costs included in the 2008 projected test year should be reduced by $700,000 on a total Company basis to reflect this known and measurable change.

Q. ARE YOU RECOMMENDING ANY REVISIONS TO THE ACTUARIAL ASSUMPTIONS UTILIZED BY THE COMPANY IN PROJECTING ITS 2008 TEST YEAR PENSION AND PBOP COSTS?

A. Yes. In the confidential response to MDR Data Request 2.28, Confidential Attachment MDR 2.28, the Company provided the assumptions utilized in projecting the pension and PBOP costs for the test year that are included in the filing. Based on that response, I recommend that the assumed long term rate of return on plan assets for both the pension plan and the PBOP plan be increased for purposes of projecting the 2008 pension and PBOP expense.

Q. DID YOU ASK THE COMPANY TO QUANTIFY THE IMPACT OF THIS RECOMMENDATION?

A. CCS Data Requests 22.2 and 22.3 asked RMP to provide an updated pension and PBOP expense due to increasing its asset return assumption from the amount utilized in its filing and identified in MDR 2.28 to 8.0%, along with other updates. The Company's response to each of these questions indicated that it had "…not modeled this impact." While the Company did not provide the requested information, in the response it did indicate that its 2007 Form 10-K disclosed that a 0.50% change in the expected return on assets would result in an approximately $4 million change in 2007 pension expense and a $2 million change in 2007 PBOP Expense. The impact specific to the projected 2008 pension and PBOP costs was not provided as requested.

Q. WHAT IS THE LONG TERM ASSET RETURN ASSUMPTION USED BY THE COMPANY IN PROJECTING ITS 2008 PENSION AND PBOP COSTS AND HOW DOES THAT RATE COMPARE TO PRIOR RATES UTILIZED AND RATES BEING USED BY OTHER ENTITIES?

A. According to the Company's 2007 Form 10-K, PacifiCorp's pension and PBOP actuarial assumptions utilized in deriving the 2007 pension and PBOP expense included a projected expected long term return on plan assets of 8.00%. This assumption is based on projected long term returns on the assets as opposed to assumptions regarding potential returns at one point in time. An annual survey conducted by Deloitte Consulting entitled "2007 Survey of Economic Assumptions Used for FAS No. 87, 106, 132, 158 and Related Measurements" indicated that the average expected long term rate of return assumption used by the entities included in its survey was 8.16%.

In response to MDR 2.28, the Company identified the long term rate of return assumption utilized in its pension and PBOP projections for 2008 as ****BEGIN CONFIDENTIAL **** **
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Q. HAVE THE ACTUARIAL ASSUMPTIONS THAT WILL BE USED BY THE COMPANY IN DETERMINING ITS PENSION AND PBOP COSTS FOR FINANCIAL REPORTING PURPOSES IN 2008 BEEN DETERMINED AT THIS TIME?

A. Not that I am aware of. The amounts in the filing would be based on assumptions for 2008 at the time the filing was prepared and may differ from the assumptions that are ultimately used for financial reporting purposes in determining the 2008 pension and PBOP expense on the Company's books and records.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED CHANGES TO THE PENSION AND PBOP COSTS?

A. As addressed above, RMP indicated in response to discovery and in its 2007 Form 10-K that a 50 basis point (0.50%) change in the expected long term rate of return on plan assets results in an approximately $4 million change in 2007 pension expense and a $2 million change in 2007 PBOP Expense. Utilizing this information provided by the Company, presumably a 25 basis point, or 0.25%, increase in the long term rate of return assumption would reduce 2008 pension expense by approximately $2 million and 2008 PBOP expense by approximately $1 million dollars.

Combining the recommended adjustments to reflect the impacts of actual 2007 plan experience and a 25 basis point increase in the long term rate of return assumptions from that utilized by RMP would result in $3.1 million reduction in pension expense and a $1.7 million reduction in PBOP costs. The net impact of both adjustments on projected 2008 expenses contained in the filing, on a Utah jurisdiction basis and after application of the capitalization factor, would be a reduction of $1.5 million. This adjustment is reflected in Exhibit CCS 2.5.

Incremental Generation O&M Expense

Q. THE COMPANY'S FILING INCLUDES AN ADJUSTMENT TO REFLECT ITS PROJECTED INCREMENTAL OPERATION AND MAINTENANCE (O&M) COSTS TO BE INCURRED AS A RESULT OF THE ADDITION OF NEW GENERATION ASSETS, SUCH AS THE WIND FACILITIES. ARE YOU RECOMMENDING ANY REVISIONS TO THE COMPANY'S ADJUSTMENT?

A. Yes. Included in the Company's adjustment are projected operation and maintenance costs for the Glenrock and Seven Mile Hill wind facilities. The Company does not project that these facilities will be placed into service until the very last day of the test year, December 31, 2008. In response to DPU Data Request 38.2, RMP agreed that there would not be any O&M expenses in 2008 for the Glenrock and Seven Mile Hill projects. Exhibit CCS 2.6 removes the O&M costs included by RMP in its filing for each of these projects of $377,072 ($159,791 Utah) and $890,936 ($377,551 Utah), respectively.

Q. EXHIBIT CCS 2.6 ALSO INCLUDES AN ADJUSTMENT TO THE LEANING JUNIPER OPERATION AND MAINTENANCE EXPENSES. WHAT IS THE PURPOSE OF THIS ADJUSTMENT?

A. Leaning Juniper was placed into service during the base year utilized by RMP in its case. In its incremental generation O&M expense adjustment, RMP included an adjustment to annualize the operating costs associated with the wind facility. ****BEGIN CONFIDENTIAL** ** ** ** ** ** ** **END CONFIDENTIAL*****

As shown in Exhibit CCS 2.6, the combined impact of the adjustments identified above is $1,485,758 ($629,618 Utah) reduction to expense.

Escalation Expense

Q. **WOULD YOU PLEASE ADDRESS THE COMPANY'S PROPOSED ESCALATION ADJUSTMENT AND THE SOURCE OF THE ESCALATION FACTORS PROPOSED BY THE COMPANY?**

A. In its filing, RMP escalated its non-labor costs in the base year using functional specific escalation factors (Global Insight Indices) prepared by Global Insight's Utility Cost Information Service and contained in Global Insight's Power Planner for the second quarter of 2007, which was released October 8, 2007. The Power Planner provides projected indexes at either the individual FERC account level or based on the weighted FERC level indexes for major FERC expense categories. In its filing, PacifiCorp uses the Global Insight indices based on the weighted FERC level indexes by major FERC expense categories as opposed to the individual FERC account level. The factors used exclude labor expenses and are based on materials and supplies. RMP utilized escalation rates based on the difference between the December 2008 indices and the June 2007 indices to account for 1.5 years of escalation in going from the base year to the test year.

Q. DO YOU RECOMMEND THAT THE FACTORS PROPOSED BY ROCKY MOUNTAIN POWER BASED ON THE PRICE INDICES DETERMINED BY GLOBAL INSIGHT BE ACCEPTED IN THIS CASE?

A. No, I do not. I recommend that the factors proposed by the Company, ranging from 1.3% to 5.7% depending on the specific FERC account being escalated, be replaced with an escalation factor of 1.25% for all of the accounts. This lower escalation rate is likely to be more reflective of escalation pressures RMP anticipates facing in going from the base year ended June 30, 2007 to the test year ending December 31, 2008.

Q. WHY DO YOU RECOMMEND THE GLOBAL INSIGHT FACTORS BE REPLACED WITH AN ESCALATION FACTOR OF 1.25%?

A. The Company's budgets and projections for its operations reflect that the Company does not anticipate it will be subject to significant inflation factors as such pressures will be absorbed through labor and procurement efficiencies. *****BEGIN CONFIDENTIAL*****

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It should be noted that the operating budget information provided by the Company for 2008 in response to MDR data request 2.12 is more recent than that used by the Company at the time it prepared its rate case filing.

Q. HOW DID YOU DETERMINE THAT THE COMPANY DID NOT USE THE UPDATED OPERATING BUDGET INFORMATION AT THE TIME IT PREPARED ITS FILING?

A. In his direct testimony, RMP witness Steven McDougal indicates at page 13 that the Company does a high level comparison of the budget and the forecast test period to capture additional adjustments necessary in the forecast test period. Additionally, at page 12, Mr. McDougal indicates that the escalated amounts in the filing were compared to Company budgets, and if significant differences existed, the escalated amounts were adjusted. CCS data requests 3.16 and 3.17 requested copies of the referenced analysis of the test year amounts to the budgets. The response provided a very high level comparison with very little detail. However, it was noted that the budgeted amounts used in the comparisons differed from the operating budgets provided by RMP in response to MDR 2.12. When asked about the discrepancy, the Company replied in response to CCS Data Request 12.8 that the response to MDR 2.12 was an updated budget that had been finalized and approved. The budget used in the comparison made by the Company during the preparation of its rate case was based on preliminary budget information that subsequently changed. The budgeted O&M expenses for 2008 apparently declined subsequent to the preparation of the Company's rate case filing.

Q. WHY ARE YOU UTILIZING A FACTOR OF 1.25% IN YOUR ESCALATION ADJUSTMENT?

A. In response to MDR 2.13, the Company provided a copy of its “2007-2016 Budget and Ten-Year Plan Guidelines.” These are the guidelines that would have been used by the Company in preparing its 2007 budget and forecast for 2008 through 2016. Based on that document, in preparing its 2007 budget, RMP assumed a non-labor inflation rate for fiscal year 2007 of 2.5%. Based on more recent information provided in response to discovery in this case, RMP does not anticipate that it will experience overall increases in O&M expense consistent with inflation in going from 2007 to 2008. The base year used in this case spans both 2006 and 2007. (July 1, 2006 to June 30, 2007) Consequently, I recommend that the base year expenses be escalated for one-half year of inflation to reflect a 2007 expense level. Based on the Company’s own internal budget assumptions used in preparing the 2007 budget, 50% of the 2007 inflation rate would be 1.25%. I recommend this rate be used in escalating non-labor O&M expense.

It should be noted that this adjustment applies only to non-labor and non-power cost related O&M expenses. The labor expenses are escalated based on projected salary and wage increases. This is addressed in the direct testimony of Committee witness Helmuth Schultz. Thus, while I am recommending that the non-labor and non-power cost

O&M expenses be escalated at 1.25%, higher escalation factors are being applied to labor costs in the 2008 test year.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED REVISION TO THE ESCALATION RATES?

A. The Company's filing included approximately $18.8 million in non-labor O&M escalation expense on a total Company basis. The adjustment necessary to reflect the 1.25% escalation rate is provided on Exhibit CCS 2.7 and results in a $13,456,104 reduction on a total Company basis ($5,856,025 Utah). This would allow for a non-labor escalation increase of $5,350,770 on a total Company basis.

<u>Overhaul Expense</u>

Q. IN THE PRIOR RATE CASE RMP MADE AN ADJUSTMENT TO GENERATION OVERHAUL EXPENSES TO NORMALIZE THE EXPENSE LEVEL AS COMPARED TO THE ESCALATED BASE YEAR AMOUNT. DID THE COMPANY MAKE A SIMILAR ADJUSTMENT IN THE CURRENT CASE?

A. No, it did not. In the prior rate case, the Company's adjustment indicated that the base year generation overhaul expenses were lower than in previous years and lower than the forecasted costs. As a result, the Company made an adjustment in that case to increase its generation overhaul O&M expense in the forecasted test year. In the current case, the Company did not present a similar adjustment. Thus, the test year costs are included in the filing based on the base year cost with the proposed escalation factors applied.

Q. HOW DOES THE BASE YEAR OVERHAUL O&M EXPENSE COMPARE TO OTHER PERIODS AND FORECASTED AMOUNTS?

A. The base year generation overhaul O&M costs are significantly higher than prior periods and forecasted amounts. Additionally, due to the apparent timing of projects during the base year, the base year costs are also significantly higher than the 2006 and 2007 calendar expense. The base year would include 6-months of 2006 and 6-months of 2007 expense levels. The table below presents actual historical expense levels, along with the base year expense.

Fiscal Year 2003	29,669,000
Fiscal Year 2004	26,350,000
Fiscal Year 2005	20,666,000
Calendar Year 2006	32,553,000
Calendar Year 2007	33,352,000
Base Year Ended 6/30/07	40,082,000

Clearly the base year expense level of $40.082 million is not reflective of a normalized cost level. It is also not reflective of a projected going-forward cost level.

Q. HAS THE COMPANY PROVIDED ITS BUDGETED 2008 GENERATION OVERHAUL O&M EXPENSE LEVEL?

A. Yes. In response to CCS Data Request 9.23, RMP provided its projected 2008 expense level of $27,687,000.

Q. WHAT ADJUSTMENT SHOULD BE MADE TO THE TEST YEAR GENERATION O&M OVERHAUL EXPENSE CONTAINED IN THE FILING?

A. On Exhibit CCS 2.8.1, I calculated a four-year average expense level based on the information I had available. The average is derived utilizing fiscal years 2004 and 2005 and calendar years 2006 and 2007. In the Company's GRID Model, it is my understanding that generation unit maintenance outages are factored into the model based on four-year average levels in order to normalize the impacts of overhaul outages on the power cost calculations. Consistent with this treatment, utilization of a four-year average cost level for overhaul operation and maintenance expense would also be reasonable. As shown on Exhibit CCS 2.8.1, the resulting four-year average expense is $28,230,000, which is $11,852,000 less than the base year level. On Exhibit CCS 2.8, I have reduced expenses by $12,352,663 ($5,234,675 Utah) to reflect the normalized level. This consists of the $11,852,000 reduction to the base year level, plus removal of $501,025 which is the escalation on the base year amount utilizing the 1.25% escalation rate recommended in this testimony ($40,082,000 x 1.25%). If the Commission does not agree with my proposed escalation expense adjustment to reflect a 1.25% escalation factor, then the recommended generation overhaul O&M expense adjustment presented above should be increased to remove the escalation applied to the base year level of generation overhaul O&M expense included in RMP's filing.

Q. SINCE THE CURRENT CREEK AND LAKE SIDE PLANTS WERE NOT OPERATIONAL IN ALL OF THE FOUR YEARS UTILIZED IN DETERMINING YOUR RECOMMENDED AVERAGE COST LEVEL, ARE YOU CONCERNED THE COMPANY WILL UNDER RECOVER ITS GENERATION OVERHAUL O&M COSTS?

A. No. In his direct testimony, Committee witness Randall Falkenberg has made an adjustment to allow for additional overhaul costs associated with these two units. Thus, the total generation overhaul O&M expenses included by the Committee includes the $28,230,000 plus additional costs associated with the Current Creek and Lake Side units. The adjustment included in Mr. Falkenberg's Table 1 combined with the fact that my recommended allowance exceeds the amount the Company has budgeted for 2008 alleviates any concerns regarding potential under recovery of such costs.

Q. IF THE COMMISSION DOES NOT AGREE WITH YOUR PROPOSED ADJUSTMENT TO NORMALIZE GENERATION OVERHAUL COSTS

BASED ON A FOUR-YEAR AVERAGE, IS THERE AN ALTERNATE ADJUSTMENT YOU WOULD RECOMMEND?

A. Yes. One of the reasons a four-year average cost level is being recommended is because generation overhaul costs will fluctuate from year to year depending upon the timing of the planned maintenance. As rates are typically set for a period exceeding one-year, inclusion of an average or normalized level in determining rates is appropriate. However, it is my understanding that RMP may file another rate case in Utah in the near future. As a result, it does not appear likely at this time that the rates resulting from the current case will remain in effect for an extended period of time. Given that fact, it would not be unreasonable for the Commission to base the generation overhaul O&M expense on the Company's budgeted 2008 amount of $27,687,000. This would increase the adjustment to reduce the expense from $11.85 million to $12.4 million on a total Company basis prior to the impact of the escalation on the base year level. This is derived from the base year cost of $40,082,000 less the budgeted 2008 cost of $27,687,000. The associated escalation on the base year level should also be removed.

<u>Property Tax Expense</u>

Q. IS THE PROJECTED 2008 PROPERTY TAX EXPENSE IN THE COMPANY'S FILING A REASONABLE PROJECTION?

A. No, it is not. In going from the base year ended June 30, 2007 to the projected test year ending December 31, 2008, the Company projected a $13,052,051 or 18.8% increase. This increased the base year property tax expense from $69,347,949 to a proposed 2008 expense of $82,400,000.

Q. HAS THE COMPANY PROVIDED ANY INDICATION THAT IT INTENDS TO REVISE THIS AMOUNT?

A. Yes. In response to DPU Data Request 21.1, the Company indicated that the receipt of its actual 2007 tax bills resulted in lower 2007 property tax expenses than it had projected at the time it estimated the property tax expense in its initial filing. The response indicated that the Utah tax bills for 2007 revealed an "unanticipated 6% decline in overall Utah property tax rates." Similar declines also occurred in other PacifiCorp jurisdictions as compared to what PacifiCorp had projected at the time of preparing its filing. In response to DPU Data Request 21.1, the Company provided a revised estimate of its 2008 property tax expense, which reduced the $82.4 million contained in its supplemental filing to $79.67 million on a total Company basis.

Q. SHOULD THE PROPERTY TAX EXPENSE CONTAINED IN THE SUPPLEMENTAL FILING FOR 2008 OF $82.4 MILLION BE REVISED

TO THE $79.67 MILLION PROJECTION IDENTIFIED IN RMP'S RESPONSE TO DPU DATA REQUEST 21.1?

A. No. The Company's revised projection is still significantly overstated and a lower projected 2008 property tax expense should be utilized. The Company's projection is significantly out of line with historical changes in the level of property tax expense and the Company has consistently over-projected property tax expenses by large amounts in prior rate case proceedings. The actual total Company property tax expense along with the annual percentage change in that expense for the period 2003 through 2007 is presented below:

2003 Property Tax Expense	67,067,823	
2004 Property Tax Expense	65,005,807	-3.07%
2005 Property Tax Expense	64,942,799	-0.10%
2006 Property Tax Expense	67,506,520	3.95%
2007 Property Tax Expense	69,102,427	2.36%

Q. PLEASE ADDRESS HOW THE PROJECTED AMOUNTS FROM RMP'S PRIOR RATE CASES COMPARE TO THE ACTUAL PROPERTY TAX EXPENSE INCURRED.

A. In Docket No. 04-035-42, the Company utilized a projected test year ending March 31, 2006. In that filing, the Company projected property tax expense for that period of $71,661,000. The actual property tax expense for the twelve-months ended December 31, 2005 and December 31, 2006 was $64.9 million and $67.5 million, respectively. Each of these amounts is considerably lower than that projected by the Company in the rate case filing.

In Docket No. 06-035-21, the Company utilized a projected test year ending September 31, 2007. In that filing, RMP projected property tax expense for that period of $75 million. The actual property tax expense for the twelve-months ended December 31, 2007 was $69.1 million.

Q. WHAT IS YOUR RECOMMENDATION FOR THE AMOUNT OF PROPERTY TAX EXPENSE TO INCLUDE IN THE TEST YEAR ENDING DECEMBER 31, 2008?

A. I recommend that property tax expense be included for the 2008 test year at $70,736,062 on a total Company basis. The calculation of this recommended amount is presented on Exhibit CCS 2.9 and is based on the actual 2007 property tax expense escalated by the actual percentage increase experienced by PacifiCorp in 2007 of 2.36%. This results in a $11,662,989 decrease ($4,922,947 Utah) in property tax expense from that contained in the supplemental filing.

As demonstrated in the table presented above, over the past five years the total amount of property tax expense incurred by PacifiCorp has fluctuated from year to year, ranging from a decline of 3.07% to an increase of 3.95%. This is all during a period of rapid investment and significant increases in net plant in service. Changes in assessment values and property tax rates in the various states in which PacifiCorp operates have helped to mitigate increases caused by the increasing net plant balances. There is no reason to now assume that the annual increase in property tax expense will jump significantly as projected by the Company. Such projections have proven to be inaccurate in the past several rate case proceedings.

Penalty Settlement Fees

Q. WHAT IS THE PURPOSE OF YOUR ADJUSTMENT ON EXHIBIT CCS 2.10 TITLED "REMOVE PENALTY SETTLEMENT FEES"?

A. During the base year, RMP booked $1,833,333 associated with the settlement in a Sierra Club lawsuit for PacifiCorp's share of the Jim Bridger Plant opacity exceedance liability. The amount consisted of $1,333,333 identified as regulatory penalties and fines and $500,000 identified in the journal entry as settlement fees[1]. While the $1,333,333 of regulatory penalties and fines were booked below-the-line, the $500,000 in settlement fees were booked to FERC Account 506 – Miscellaneous Steam Expense. The adjustment on CCS Exhibit 2.10 removes these settlement fees from expense, along with escalation on these base year costs at the 1.25% escalation factor recommended in this testimony, reducing expenses by $506,250 ($211,885 Utah). If the Commission

[1] Response to CCS data request 20.2.

elects to accept the Company's proposed escalation factors, then the adjustment should be increased to $524,000 based on the 4.8% escalation factor applied by RMP to FERC Account 506.

<u>Income Tax Expense</u>

Q. DO YOU HAVE ANY CONCERNS WITH THE INCOME TAX EXPENSE CALCULATIONS CONTAINED IN THE COMPANY'S FILING?

A. Yes, I do. On February 13, 2008, President Bush signed The Economic Stimulus Act of 2008 (The Act) into law. This Act allows for considerable bonus depreciation for income tax purposes. Most utility plant additions qualify for the bonus depreciation. Under the 2008 Act, bonus depreciation of 50% is allowed for plant placed into service before January 1, 2009 or, in the case of certain property having a longer production period, before January 1, 2010. The bonus depreciation results in an impact on the accumulated deferred income tax offset to rate base as the depreciation deduction for income tax purposes in the years the bonus depreciation is in effect is considerably higher than the recorded depreciation expense on the Company's books. Plant additions for which the Company had a binding contract prior to January 1, 2008 would not qualify under The Act. Thus, the wind projects contained in the filing would not qualify, but many other items in the Company's projected 2008 plant additions included in the filing will qualify for the bonus depreciation.

Q. DID YOU ASK THE COMPANY TO PROVIDE THE IMPACTS OF THE ACT ON ITS FILING?

A. Yes, both the Committee and the DPU requested the Company to provide an estimate of the impacts of The Act on its filing. The Company responded in DPU Data Request 27.4 as follows:

> "The Company has not yet determined which projects can be moved from 2009 to 2008 that would qualify for this business tax incentive package. Once this determination is made, the Company should be able to estimate the impact. However, to incorporate this impact on the current Utah case would mean the Company would have to adjust the case in order to move capital additions to coincide with the estimated deferred tax data resulting from this incentive."

Q. IN YOUR OPINION, IS THE COMPANY'S RESPONSE ACCURATE AND COMPLETE?

A. No, it is not. There are many projects included in the Company's projected 2008 additions to plant in service that would qualify for the special bonus depreciation treatment. Receiving benefits under The Act would not require the Company to accelerate the time table for projects from 2009 into 2008. As the Company has not done the calculations necessary and has the best access to its tax system and the information needed to determine which of the 2008 additions qualify under The Act, the Company should be required to quantify the impact on accumulated deferred income tax so that the income tax savings can be reflected in the revenue requirement calculations in this case.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, at this time. However, there are several data requests outstanding and several responses have been recently received. The review and analysis of these responses may result in additional adjustments being warranted.