Q. Please state your name, business address, and present position with Rocky Mountain Power (the Company), a division of PacifiCorp.

A. My name is Steven R. McDougal, and my business address is 201 South Main, Suite 2300, Salt Lake City, Utah, 84111. I am currently employed as the director of revenue requirements for the Company.

Qualifications

Q. Please briefly describe your education and business experience.

A. I received a Master of Accountancy from Brigham Young University with an emphasis in Management Advisory Services in 1983 and a Bachelor of Science degree in Accounting from Brigham Young University in 1982. In addition to my formal education, I have also attended various educational, professional, and electric industry-related seminars. I have been employed by Rocky Mountain Power or its predecessor companies since 1983. My experience at Rocky Mountain Power includes various positions within regulation, finance, resource planning, and internal audit.

Q. Please describe your present duties.

A. My primary responsibilities include overseeing the calculation and reporting of the Company's regulated earnings or revenue requirement, assuring that the inter-jurisdictional cost allocation methodology is correctly applied, and explaining those calculations to regulators in the jurisdictions in which the Company operates.

Q. Have you testified in previous proceedings?

A. Yes. I have provided testimony before the Utah Public Service Commission, the

Washington Utilities and Transportation Commission, the California Public Utilities Commission, the Idaho Public Utilities Commission, the Wyoming Public Service Commission, and the Utah State Tax Commission.

Purpose of Testimony

Q. What is the purpose of your direct testimony?

A. My direct testimony addresses the calculation of the Company's Utah-allocated revenue requirement and the revenue increase requested in the Company's application. In support of this calculation, I provide testimony on the following:

- A summary of the calculation of the $66.9 million requested rate increase.
- Details of the test period utilized in this case, the twelve months ending June 30, 2010 ("Test Period"), and the Company's process for compiling the Test Period revenue requirement.
- Based on the Utah-allocated adjusted results of operations for the Test Period, current rates without the requested increase will produce an overall return on equity ("ROE") in Utah of 8.9 percent.

Revenue Requirement Summary

Q. What price increase is required to achieve the requested ROE in this case?

A. Exhibit RMP___(SRM-1) provides a summary of the Company's Utah-allocated results of operations for the Test Period, twelve months ending June 30, 2010. At current rate levels Rocky Mountain Power will earn an overall ROE in Utah of 8.9 percent during the Test Period. This return is less than the 11.0 percent return recommended by Dr. Samuel C. Hadaway in this case. An overall price increase of $79.4 million would be required to produce the 11.0 percent ROE requested by the Company in this proceeding to provide a fair and equitable return for the Company's shareholders. In this case the price increase is limited to $66.9 million due to the Rate Mitigation Cap.

Q. Please explain the Rate Mitigation Cap.

A. The Company's calculations of Utah's results of operations and the associated ROE are based on the Revised Protocol allocation method as approved by the Commission in Docket No. 02-035-04. One component of the stipulation approved by the Utah PSC in that docket is the Rate Mitigation Cap. The stipulation states:

> "In order to mitigate potential rate impacts on Utah customers, any increase in the Utah revenue requirement as a result of the implementation of the Revised Protocol shall be capped at the Applicable Percentage of the Company's Utah Revenue Requirement calculated under the Rolled-In Allocation Method for the indicated effective periods as follows:
>
> a. 101.5 percent for the period from the effective date of the final PSCU order in the first general rate proceeding filed after the effective date of this Stipulation and the Revised Protocol, to March 31, 2007.
>
> b. 101.25 percent for the period from April 1, 2007 to March 31, 2009."[1]
>
> "for the Company's fiscal years beginning April 1, 2009 through March 31, 2014, for all general rate proceedings, the Company's Utah revenue requirement to be used for purposes of setting rates for Utah customers will be the lesser of: (1) the Company's Utah revenue requirement calculated under the Rolled-In Allocation Method multiplied by 101.00 percent; or (ii) the Company's Utah revenue requirement resulting from the Revised Protocol."[2]

For purposes of this case the Company utilized a 101.00 percent cap which reduces Utah's revenue requirement by $12.5 million. Consequently, the

[1] Stipulation in Docket No. 02-035-04, page 3.
[2] Stipulation in Docket No. 02-035-04, page 4.

Company is requesting a price change of $66.9 million as shown in my Exhibit RMP___(SRM-1) page 1.

Q. Please explain the key area where the Company has experienced cost increases that support the $66.9 million required price increase.

A. The Company continues to incur cost increases to serve its customers through its capital investment plan, which is the main driver of the revenue requirement increase requested in this case. The Company is planning to add $2.1 billion in new electric plant in service between December 2008 and June 2010. As a result, the total Company average electric plant in service during the test period will be over $1.4 billion higher than the December 31, 2008 actual level. This increase includes the following:

- Steam and Hydro plant additions of $308 and $51 million respectively.
- Other plant additions, mainly wind, of $543 million. This case includes the McFadden Ridge I wind project, described in the testimony of Mr. A. Robert Lasich, as well as well as recovery of a greater portion of various new generating facilities that were only partially included in the last case by virtue of the average rate base convention.
- Over $200 million in new transmission investment.
- Distribution plant additions of $243 million, with $118 million being within the state of Utah.

Test Period and Revenue Requirement Preparation

Q. What test period did the Company use to determine revenue requirement in this case?

A. The Company projected results of operations for the period of time beginning July 1, 2009, and ending June 30, 2010. The Test Period utilizes an average (13 month) rate base with a calendar year 2008 historical base period.

Q. Why did the Company utilize the year ending June 30, 2010, as the Test Period?

A. The Test Period is based on the all-party Test Period Stipulation reached May 13, 2009, and subsequently approved by the Commission at hearing on May 21, 2009. The Company believes the Test Period is conservative and balances the need for adequate cost recovery with the need for transparency and risk sharing between the Company and its customers.

Q. Please explain how the newly-enacted Utah Code Annotated Section 54-7-13(4), passed as part of Senate Bill 75, affected the Company's Test Period.

A. Section 54-7-13(4) allows a utility to recover the costs of major plant additions by filing an application for approval of a major plant addition within 150 days from the capital addition's scheduled in service date. Per this statute, a major plant addition is defined as "any single capital investment project of a gas corporation or an electrical corporation that in total exceeds 1 percent of the gas corporation's or electrical corporation's rate base". The Company has identified four major projects for which it currently intends to seek cost recovery via separate major plant addition filings under this statute during 2010.

Q. Are any of the major plant additions included in the Test Period in this case?

A. No. Rocky Mountain Power has removed the Dave Johnston power plant scrubber investment and the Ben Lomond to Terminal transmission line segment from the June 2010 test period. Two other major plant additions are scheduled to go into service later in 2010 and will also be addressed through major plant addition rate recovery.

Q. Please explain how the Company developed the revenue requirement for the Test Period.

A. Revenue requirement preparation began with historical accounting information; in this case the Company used the twelve months ended December 31, 2008. Each of the revenue requirement components in that historical period was analyzed to determine if an adjustment would be warranted to reflect normal operating conditions. The historical information was adjusted to recognize known, measurable, and anticipated events and to include previously ordered Commission adjustments.

Q. What is the significance of Rocky Mountain Power's method of beginning with historical information?

A. The Company begins with historical accounting information and makes discrete adjustments to arrive at the Test Period revenue requirement. Beginning with historical information provides a realistic foundation that is readily available for audit by all participants involved in the case. Individual adjustments are also available for review, and regulators and intervenors may determine each adjustment's relevance and accuracy.

Q. Please summarize the process used to adjust the historical accounting information to reflect Test Period results of operations.

A. Historical retail revenue is first adjusted to reflect normal weather conditions and remove items that should not be included in regulated results. Revenue is also adjusted for the effect of applying the current Commission-approved tariff rates to the Test Period load projection. The testimony of Dr. Peter C. Eelkema describes the comprehensive approach used to project Test Period loads for this case. Net power costs were developed using the Generation & Regulation Initiative Decision ("GRID") model, which has been used extensively in prior general rate cases and other regulatory proceedings in Utah. The calculation of Test Period net power costs is described in the testimony of Company witness Mr. Gregory N. Duvall. Historical operations and maintenance ("O&M") expenses, excluding net power costs, were split into labor and non-labor components. Non-labor costs were adjusted for projected price changes using nationally-recognized inflation indices provided by Global Insight and for other discrete changes required to reflect conditions expected during the Test Period. Historical labor costs were also adjusted for expected increases through the end of the Test Period. Rate base was adjusted to capture planned additions to electric plant in service, with the exception of projects which will be included in major plant addition applications, and known changes to other rate base items. In addition, asset retirements and accumulated depreciation were walked forward through the end of the Test Period based on composite retirement and depreciation rates by plant function. Specific adjustments are described in greater detail later in my testimony and exhibits where I explain the development of the Utah results of operations.

Q. How has the Company addressed areas where the expected change in O&M is different than the price changes projected by Global Insight?

A. The revenue requirement developed in the case was compared to the Company's budget on a high level, and the Company's business units provided regulation with any areas where budgets were significantly different than adjusted amounts. When differences were identified the business units provided support for changes in the number or frequency of activities. Examples of these types of adjustments are the Utah Automated Meter Reading ("AMR") adjustment (Adjustment 4.18) which reflects efficiencies from the automated meter reading project, and the Incremental Generation O&M adjustment (Adjustment 4.6) which includes the cost of operating and maintaining new plants. These adjustments are necessary because inflation indices are applied to costs for existing units of production which will not capture changes in volume or processes. Finally, in this case an adjustment is made to reduce non-power cost O&M expense to the level in the Company's budget.

Utah Results of Operations

Q. Please describe Exhibit RMP___(SRM-2).

A. Exhibit RMP___(SRM-2), which was prepared under my direction, is Rocky Mountain Power's Utah results of operations report (the "Report"). The historical starting point for the Report is the twelve months ended December 31, 2008, which was normalized and used to calculate the revenue requirement for the Test Period, the twelve months ending June 30, 2010. The Report provides totals for revenue, expenses, depreciation, net power costs, taxes, rate base, and loads in the Test Period. Electric plant in service, accumulated depreciation, and amortization reserve balances are calculated using a thirteen month average (matching generation investment with maintenance and net power costs). All other rate base items use a 2008 historical year end starting point and if applicable are forecasted out to a June 2009 and June 2010 average amount. The Report presents operating results for the period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit RMP___(SRM-2) is organized.

A. The Report is organized into sections marked with tabs. Tab 1 Summary contains the Utah-allocated results according to the Revised Protocol allocation methodology. Page 1.0 is the calculation of the capped revised protocol price change of $66.9 million. It details the calculation of the Rate Mitigation Cap which compares the revenue requirement from the Rolled-In allocation method to the Revised Protocol allocation method and caps the increase at the lower of Revised Protocol or 101.0 percent of Rolled-In. Page 1.1, starting with the left-hand column 1 labeled Total Adjusted Results, displays the Utah results of operations for the Test Period. The Total Adjusted Results column is carried forward from the results of operations summary, page 2.2, and shows a ROE for Utah of 8.9 percent. The Price Change (column 2 of Tab 1, page 1.1) shows that an increase of $79.4 million in revenues is required to increase the return on equity from 8.9 percent to 11.00 percent in Utah. Column 3 reflects the Utah adjusted revenue requirement of $1.55 billion with the $79.4 million price increase included. Page 1.2 of Tab 1 supports the calculation of additional revenue-related uncollectible expense and franchise taxes associated with the price change requested in column 2. Page 1.3 details the calculation of the net operating income percentage. Page 1.4 shows the same details as page 1.1 under the Rolled-In rather than the Revised Protocol allocation method. It is used in calculating the rate mitigation cap on page 1.0. Pages 1.5 through 1.6 contain a summary of adjustments made to the actual results to arrive at the Test Period.

Tab 2 details Total Company and Utah-allocated results based on the Revised Protocol allocation methodology. Pages 2.3 through 2.39 contain Total Company and Utah-allocated revenue, expenses and rate base detail by FERC account. Supporting documentation for the data in Tab 2, along with the normalizing adjustments required to reflect on-going costs of the Company, is provided under Tabs 3 through 8. The calculation of these adjustments is described later in my testimony. Tab 9 is Tab 2 restated with the Utah allocation based on the Rolled-In allocation method. Tab 10 contains the calculation of the Revised Protocol allocation factors.

Tab 3 – Revenue Adjustments

Q. Please describe the information contained behind Tab 3 Revenue Adjustments.

A. Tab 3 begins with the Revenue Adjustment Index (page 3.0.1) followed by a numerical summary and the specific adjustments. The numerical summary (page 3.0.2) identifies each adjustment made to actual revenues, and the adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-2), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments made to revenue in Tab 3.

A. **Pro-Forma Revenue (page 3.1) –** This adjustment begins with December 2008 general business revenues and adjusts to the pro forma level for the twelve months ending June 2010 based on forecasted loads.

Wheeling Revenue (page 3.2) – This adjustment reflects the level of wheeling revenues the Company expects in the 12 months ending June 30, 2010 by adjusting the actual revenues for the 12 months ended December 31, 2008 for normalizing, annualizing, and pro forma changes.

West Valley Reserve Revenue (page 3.3) – The current GRID model for this filing includes reserves that the Company provides to the West Valley plant, which the Company no longer leases or operates. This adjustment takes the expected West Valley generation level included in the GRID model and multiplies it by the OASIS reserve tariff to calculate the expected revenue from the West Valley plant. This adjustment is not related to the removal of the West Valley lease in Adjustment 5.2.

SO2 Emission Allowances (page 3.4) – The Environmental Protection Agency ("EPA") has established guidelines that govern the volume of sulfur dioxide ("S02") that can be emitted from power plants and granted the issuance of S02 emission allowances to cover each ton emitted. Plants that are not in compliance with EPA guidelines may purchase emission allowances from other companies that have excess allowances. Consistent with the Commission order in Docket No.

97-035-01, the Company has amortized sales of emission allowances over a four-year period. This adjustment replaces the sales from the historical period with the appropriate annual amortization, taking into account projected sales through the Test Period.

Green Tag Revenue (page 3.5) – A market for green tags or Renewable Energy Credits (“REC”) is developing where the tag or green traits of qualifying power production facilities can be detached and sold separately from the power itself. Generally, wind, solar, geothermal and some other resources qualify as renewable resources, although each state may have a slightly different definition. California and Oregon have renewable portfolio standards that limit the Company's ability to sell green tags. Therefore, this adjustment reverses actual sales and allocates the sales for the 12 months ended June 2010 to the remaining jurisdictions.

Revenue Correcting (page 3.6) – During 2008 several entries were booked to the incorrect FERC accounts and/or locations. This adjustment corrects the accounting entries to reflect proper account assignment and allocation factors.

Tab 4 – O&M Adjustments

Q. Please describe the information contained behind Tab 4 O&M Adjustments.

A. Tab 4 includes the O&M Index (page 4.0.1) followed by a numerical summary and the specific adjustments. The numerical summary (pages 4.0.2 – 4.0.4) identifies each adjustment made to actual operations, maintenance, administrative, and general expenses and that adjustment’s impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-2), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments made to O&M expense in Tab 4.

A. **Miscellaneous General Expense (page 4.1)** – This adjustment removes certain miscellaneous expenses that should have been charged below the line to non-regulated expense accounts.

Wage & Employee Benefits (page 4.2) – Labor-related costs for the Test Period are computed by adjusting salaries, incentives, benefits, and costs associated with FAS 87 (pension), FAS 106 (post retirement benefits) and FAS 112 (post employment benefits) for changes expected beyond the actual costs experienced in 2008. Union contract agreements are used to escalate union labor group wages, while increases for non-union and exempt employees were based on budgeted increases. Incentive compensation, used by the Company to deliver market competitive pay structured in a manner that benefits customers with safe, adequate, and reliable electric service at a reasonable cost, is included at the budgeted level for the Test Period. Pension expense and other employee benefit costs were also itemized starting with 2008 and adjusted to the budgeted expense for the Test Period. These projections were provided by Mr. Erich Wilson and are supported in his testimony.

Page 4.2.1 provides further description of the procedure used to compute Test Period labor costs. Page 4.2.2 of Exhibit RMP___(SRM-2) starts with a numerical summary of actual labor costs in 2008 and summarizes the adjustments made to project costs to reflect the Test Period expense. This summary is followed by the detailed worksheets on pages 4.2.3 through 4.2.12 used to adjust the labor costs forward to the Test Period.

O&M Expense Escalation (page 4.3) – This adjustment revises non-labor expenses for projected price changes through the Test Period. Changes are based on indices produced by Global Insight, which provides a detailed assessment of the electric market both historically and into the future. The Company applies Global Insight indices to costs for materials and services only. Labor-related expenses were segregated from non-labor-related expenses and were escalated separately as described earlier in my testimony.

Global Insight's indices are prepared at the FERC functional subcategory level and are denoted with their corresponding FERC account number. The individual FERC account level indices are then combined into broader indices representing operation, maintenance, or total operation and maintenance expenses. The Global Insight data is proprietary and subject to copyright protection. The indices utilized in the Company's filing are provided in confidential Exhibit RMP___(SRM-3).

MEHC Transition Savings (page 4.4) – This adjustment removes from the historical results an entry crediting expense to establish a Wyoming MEHC change-in-control severance regulatory asset. Deferral of MEHC transition costs was not allowed by the Commission's order in Docket No. 07-035-04 issued January 3, 2008.

Irrigation Load Control Program (page 4.5) – Incentive payments made to Idaho customers participating in the irrigation load control program were initially system allocated in unadjusted data. This adjustment corrects that allocation and assigns these costs directly to Idaho consistent with other demand side management programs.

Incremental Generation O&M (page 4.6) – Generation O&M expenses for generation plants placed in service during 2008 are adjusted to the level expected in the Test Period. Such generation plants include the Goodnoe Hills wind plant, Marengo II wind plant, Glenrock wind plant, Seven Mile Hill wind plant, Seven Mile Hill II wind plant, and the Chehalis gas plant. Incremental O&M expenses are also added for generating units that were not in service during the twelve months ended December 2008 but will be in service during the twelve months ending June 2010.

Additionally, this adjustment removes funding received during 2008 from the Energy Trust of Oregon ("ETO") related to the Goodnoe Hills wind plant. This is consistent with the stipulation in Docket No. 08-035-38 which stated:

> "The Parties agree that the overall revenue requirement in this Stipulation does not include any consideration of funds received by Rocky Mountain Power from the ETO pursuant to the project funding agreement for the Company's Goodnoe Hills wind plant. As a result, if the Stipulation is approved, Utah will retain its full share of renewable energy credits associated with Goodnoe Hills."

Remove Non-Recurring Entries (page 4.7) – A few accounting entries were made to expense accounts during the twelve months ended December 2008 that are non-recurring in nature or relate to a prior period. These transactions are removed from results of operations to normalize the Test Period results. Details on the specific items in the adjustment can be found on page 4.7.1 of Exhibit RMP___(SRM-2).

MEHC Affiliate Management Fee Commitment (page 4.8) – This adjustment complies with the MEHC acquisition commitment 38 which states:

> "MEHC commits that the corporate charges to PacifiCorp from MEHC and MEC will not exceed $9 million annually for a period of five years after the closing on the proposed transaction."

The billings for the period twelve months ended December 2008 were below this limit. This adjustment removes the below the line portion of the billing included in base year results.

Preliminary Plant Expense (page 4.9) – The Company researched the possibility of installing generators at compressor stations along the Kern River pipeline. After this project was abandoned by the Company, the costs initially incurred were written off to FERC Account 557. This adjustment removes this write-off from regulatory results of operations.

Advertising Expense (page 4.10) – This adjustment removes certain advertising expenses from 2008 unadjusted regulatory results that should have been booked below the line. Consistent with Docket No. 08-035-38, the Company agreed to directly assign identifiable general rate case advertising; therefore, this adjustment removes general rate case advertising originally allocated on a system-wide basis and assigns the costs directly to the jurisdiction for which the advertising expense was incurred.

Leaning Juniper Warranty (page 4.11) – This adjustment removes the warranty costs for the Leaning Juniper I wind plant because the warranty expired in September 2008. This adjustment is consistent with the Utah Commission order in Docket No. 07-035-93.

Utah Distribution Expense (page 4.12) – This adjustment is necessary to normalize Utah distribution corrective and preventative maintenance expense for the year ended December 31, 2008. For the months of September through December 2008 the Company temporarily decreased spending for Utah distribution corrective and preventative maintenance to keep Utah costs in line with the amount the Company was allowed to recover by rates set in Docket No. 07-035-93. In 2009 the Company returned to normal activity levels and this adjustment is needed to reflect Utah distribution expense at a sustainable and normal annual level.

Pension Curtailment (page 4.13) – The Commission's Order in Docket No. 08-035-93 approved a stipulation permitting deferral and amortization of the pension curtailment gain resulting from employee participation in the 401(k) retirement plan option and for deferral and amortization of the increase in the pension and other postretirement welfare expense caused by the change in the annual measurement date mandated by FAS 158. Amortization of the measurement date change began on the books effective January 1, 2008. Amortization of the curtailment gain began on the books effective January 1, 2009. This adjustment removes the Utah actual 2008 amortization and replaces it with the pro forma Test Period amortization. This adjustment also reverses an entry for the Idaho portion booked in 2008.

WECC Fees (page 4.14) – Since its formation, the Western Electric Coordinating Council ("WECC") has been responsible for coordinating and promoting electric system reliability. Recently, WECC's role has significantly expanded into the compliance area, including enforcing auditing compliance standards and supporting power markets and non-discriminatory transmission access among members. This adjustment includes the increase in mandated membership WECC fees over the amount incurred in 2008.

Generation Overhaul Expense (page 4.15) – This adjustment normalizes generation overhaul expenses using a four year average methodology. Overhaul expenses from 2005 through 2007 are escalated to a 2008 level using escalation indices, and then those escalated expenses are averaged. For new generating units, which include Currant Creek, Lake Side, and Chehalis, the four year average is comprised of the overhaul expense planned for the first four full years these plants are operational. The actual overhaul costs for the year ended December 2008 are subtracted from the four year average which results in this adjustment.

The Company's use of a four-year historical average was approved by the Commission in Docket No. 07-035-93, as was the use of a four-year average of planned expenses for the Company's new gas plants. This treatment, including escalation of the historical components of the average, was utilized in the Company's filing in Docket No. 08-035-38. That case was settled with no finding made on the escalation issue. Without such escalation, the Company's overhaul expenses will be systematically understated by the four-year inflation factor.

The purpose of averaging is to adjust for uneven costs, not to adjust for inflation. Historical amounts need to be restated to current dollars to adjust for inflationary pressures. A simple example below shows the impact of averaging on inflation, assuming a 2.5 percent inflation rate, a $100 amount in year one, and a four year average of years one through four used to project costs in year five. Using this assumption, Example 1 shows the impact without adjusting for inflation, and Example 2 shows the impact when years one through four are adjusted for inflation to current dollars. As shown, with no escalation to account for inflation a four year average of costs is $103.8, much less than the projected costs in year five, resulting in an expense level that is 2.5 years old compared to the current expenses. In Example 2 the average is equal to the year five amount resulting in an accurate forecast.

Example 1

Year	Amount	
1	$ 100.0	
2	102.5	Avg.
3	105.1	$103.8
4	107.7	
5	110.4	

Example 2

Year	Amount	Escalation	Adjusted Amount	
1	$ 100.0	1.104	$ 110.4	
2	102.5	1.077	110.4	Avg.
3	105.1	1.051	110.4	$110.4
4	107.7	1.025	110.4	
5	110.4			

Solar Photovoltaic Program (page 4.16) – This adjustment reflects the estimated annual program costs associated with the pilot Solar Photovoltaic Utility Buy-Down Program co-sponsored by Utah Clean Energy and Rocky Mountain Power. This pilot solar photovoltaic project was implemented in September 2007 and is projected to operate at similar funding levels through 2011. The program will gather important information on the viability of a solar program funded by participating customers, tax incentives, and utility contributions.

Insurance Expense (page 4.17) – This adjustment normalizes injury and damage expenses to reflect a three year average using the cash method, consistent with the

Utah Commission ruling in Docket No. 07-035-93. This adjustment also normalizes property insurance expenses and captive property and liability insurance expenses.

Utah AMR Savings (page 4.18) – The Company replaced approximately 600,000 meters on the Wasatch Front with new radio equipped digital meters. The meters were installed by May 2008, and this adjustment captures the O&M savings due to the new Automated Meter Reading Program. The Company anticipates that the full level of ongoing savings associated with the AMR program will be realized during the test period.

Adjust O&M to 2009/2010 Target (page 4.19) – With certain exceptions the Company intends to align the non-power cost O&M in this case to the amount in the budget. Since the adjusted actual expenses are higher than budget, in this case the escalated non-power cost O&M is adjusted downward to reflect the budgeted level. A limited number of adjustments to budget were made for the following items: averaging of overhaul and insurance expenses, non-utility advertising, ETO credits, and labor adjustment. Adjustment 4.19 is dependent upon other adjustments in this filing as shown on page 4.19.2 and will change accordingly if other adjustment amounts change.

Tab 5 – Net Power Cost Adjustments

Q. Please describe the information contained behind Tab 5 Net Power Cost Adjustments.

A. Tab 5 includes the Net Power Cost Index (page 5.0.1) followed by a numerical summary and the specific adjustments. The numerical summary (page 5.0.2) identifies each adjustment made to actual expenses and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-2), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 5.

A. **Net Power Cost Study (page 5.1) –** The Net Power Cost adjustment normalizes steam and hydro power generation, fuel, purchased power, wheeling expense, and sales for resale in a manner consistent with the contractual terms of the Company's sales and purchase agreements. It also normalizes hydro, weather conditions, and plant availability as described in Mr. Duvall's testimony.

West Valley Lease (page 5.2) – The Company terminated the lease for the West Valley generating facility on May 31, 2008. This adjustment removes the associated expense and rate base to align with net power costs which do not include the West Valley plant. Amortization of the savings from the reduction in the West Valley lease expense pursuant to MEHC transaction commitment U46 ended May 31, 2008 and has no effect on the Test Period.

James River Royalty Offset & Little Mountain (page 5.3) – On January 13, 1993, the Company executed a contract with James River Paper Company with respect to the Camas mill, later acquired by Georgia Pacific. Under the agreement, the Company built a steam turbine and is recovering the capital investment over the twenty-year operational term of the agreement as an offset to royalties paid to James River based on contract provisions. The contract costs of energy for the Camas unit are included in the Company's net power costs as purchased power expense, but GRID does not include an offsetting revenue credit for the capital and maintenance cost recovery. This adjustment adds the royalty offset to FERC Account 456, other electric revenue, for the Test Period.

This adjustment also normalizes the ongoing level of steam revenues related to the Little Mountain plant. Contractually, the steam revenues from Little Mountain are tied to natural gas prices. The Company's net power cost study includes the cost of running the Little Mountain plant but does not include the offsetting steam revenues. This adjustment aligns the steam revenues to the gas prices modeled in GRID.

Green Tags (page 5.4) – This adjustment removes from regulatory results the cost of renewable energy credit or green tag purchases made for the Blue Sky program.

Electric Lake Settlement (page 5.5) – Canyon Fuel Company ("CFC") owns the Skyline mine located near Electric Lake, a reservoir owned by the Company which provides water storage for the Huntington generating plant. The two companies disputed the claim made by PacifiCorp that CFC's mining operations caused the lake to leak water into the Skyline mine, thus making it unavailable for use by the Huntington generating plant. The Company has incurred capital costs and O&M costs to pump water from the breach back into Electric Lake. The two companies negotiated a settlement of the claims. The settlement includes reimbursement to the Company for O&M and capital costs associated with the pumping. The value of the settlement is being amortized over three years. This adjustment reduces rate base for the fixed cost portion of the settlement and includes one year of amortization of the O&M portion of the settlement. This adjustment is consistent with the Company's filing in Docket No. 08-035-38.

Tab 6 – Depreciation and Amortization Expense Adjustments

Q. Please describe the information contained behind Tab 6 Depreciation and Amortization Adjustments.

A. Tab 6 includes the Depreciation and Amortization Index (page 6.0.1) followed by a numerical summary and the specific adjustments. The numerical summary (page 6.0.2) identifies each adjustment made to actual results and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-2), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount, and a brief description of the adjustment.

Q. How are the Company's pro forma depreciation and amortization expense for the Test Period developed in the Report?

A. The depreciation and amortization expense for the Test Period is calculated by applying functional composite depreciation and amortization rates to projected plant balances. Rates used are those approved by the Commission in Docket No. 07-035-13, effective January 1, 2008. Depreciation expense also includes the accrual for hydro decommissioning as approved in Docket No. 07-035-13. Details are provided on pages 6.1 through 6.1.13.

Q. How are the accumulated depreciation and amortization balances included in the filing calculated?

A. Accumulated depreciation and amortization balances for the Test Period are calculated by applying pro forma depreciation and amortization expense and plant retirements to the actual December 2008 balances. Accruals and planned spending for hydro decommissioning are also included in the adjusted depreciation reserve balance. The reserve balances are calculated on a monthly basis to walk the balances forward from December 31, 2008 through June 30, 2010. The 13-month average reserve balance is included in rate base. Calculations are detailed on pages 6.2.2 to 6.2.11.

Tab 7 – Tax Adjustments

Q. Please describe the information contained behind Tab 7 Tax Adjustments.

A. Tab 7 includes the Tax Adjustment Index (page 7.0.1) followed by a numerical summary and the specific adjustments. The numerical summary (page 7.0.2) identifies each adjustment made to the various tax components and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-2), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 7.

A. **Interest True-Up (page 7.1) –** This adjustment details the adjustment to interest expense required to synchronize the Test Period expense with rate base. This is done by multiplying normalized net rate base by the Company's weighted cost of debt in this case.

Property Tax Expense (page 7.2) – Property tax expense for the Test Period was computed by adjusting calendar year 2008 property tax expense for known or anticipated changes in assessment levels through June 30, 2010. The property tax costs in this case were estimated using methods similar to those employed by the Company when estimating property tax costs in Docket Nos. 07-035-93 and 08-035-38. These methods give necessary consideration to the effect that changes in the level of operating property and net operating income may have on state-by-state assessed values. Confidential Exhibit RMP___(SRM-4) provides a comprehensive description of the Company's property tax estimation procedures along with a detailed calculation of Test Period property taxes.

Renewable Energy Tax Credit (page 7.3) – The Company is entitled to recognize certain tax credits as a result of placing qualifying renewable generating plants into service. The federal tax credit is based on the generation of the plant, and the credit can be taken for ten years on qualifying property. Under the calculation required by Internal Revenue Service Code Sec. 45(b)(2), the current renewable electricity production credit is 2.1 cents per kilowatt hour, and this rate is expected to increase to 2.2 cents per kilowatt hour in 2010. The Utah state tax credit is based on the generation of the Blundell bottoming Cycle, and the credit can be taken for four years. In addition to the Utah tax credit, the Company is able to recognize the Oregon Business Energy Tax Credit which is based on investment in specific plants and is taken over a five year period on qualifying property.

Pro Forma Schedule M's (page 7.4) – The Schedule M items at December 31, 2008, were updated for known and measurable adjustments through June 30, 2010. Non-utility items, separate tariff items and other non-recurring items were removed from the December 31, 2008 historical period before updating. The Schedule M items were then used to develop deferred income tax expenses and balances for June 30, 2010. This adjustment incorporates all Schedule M items into the results of operations. For informational purposes, Schedule M impacts directly related to other adjustments in tabs 3 through 8 are displayed on the individual adjustment lead sheets.

Deferred Income Taxes (page 7.5 & page 7.6) – The non-property-related Schedule M items were used to develop the deferred income tax expense. The property-related deferred income tax expense was generated using the capital additions and resulting book and tax depreciation. Normalizing adjustments were added consistent with the Schedule M items as described above. The deferred income tax expense was then used to develop the deferred tax balance for the Test Period. Adjustments 7.5 and 7.6 incorporate all deferred tax expense and rate base items into the results of operations. For informational purposes, deferred tax impacts directly related to other adjustments in tabs 3 through 8 are displayed on the individual adjustment lead sheets.

Q. How have current state and federal income tax expenses been calculated?

A. Current state and federal income tax expenses were calculated by applying the applicable tax rates to the taxable income calculated in the Report. State income tax expense was calculated using the state statutory rates applied to the jurisdictional pre-tax income. The result of accumulating those state tax expense calculations is then allocated among the jurisdictions using the Income Before Tax ("IBT") factor. Federal income tax expense is calculated using the same methodology that the Company uses in preparing its filed income tax returns. The detail supporting this calculation is contained on pages 2.18 through 2.20.

Q. Docket No. 09-035-03 was recently opened to explore deferred tax normalization as it relates to Rocky Mountain Power. Does revenue requirement in this case reflect any changes to the Company's current normalization policy?

A. No. The Company's deferred income taxes in this case are calculated using 40 percent normalization of the book basis differences consistent with prior treatment of those items. However, the Company still believes that full normalization is the better approach and should be adopted by the Commission. The Commission previously accepted a transition to full normalization through a phase in approach with 20 percent adjustments in each rate case to arrive at full normalization. The current level of book basis normalization is 40 percent due to the transition in two prior rate cases.

Tab 8 – Rate Base Adjustments

Q. Please describe the information contained behind Tab 8 Rate Base Adjustments.

A. Tab 8 includes the Rate Base Adjustment Index (page 8.0.1) followed by a numerical summary and the specific adjustments. The numerical summary (pages 8.0.2 – 8.0.3) identifies each adjustment made to actual rate base and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-2), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount, and a brief description of the adjustment.

Q. Please describe each of the adjustments to the historical rate base balances.

A. **Cash Working Capital (page 8.1) –** This adjustment supports the calculation of cash working capital included in rate base based on the normalized results of operations for the Test Period. Total cash working capital is calculated by multiplying jurisdictional net lag days by the average daily cost of service. Net lag days in this case are based on the lead lag study recently prepared by the Company using calendar year 2007 information, with adjustments to the expense lag days as agreed to in the Company's rebuttal filing in Docket No. 08-035-38. Based on the results of the 2007 lead lag study as adjusted, the Company experiences 5.6 net lag days in Utah requiring a cash working capital balance of $17.7 million to be included in rate base.

Trapper Mine Rate Base (page 8.2) – The Company owns a 21.4 percent share of the Trapper Mine, which provides coal to the Craig generating plant. This investment is accounted for on the Company's books in FERC Account 123.1, investment in subsidiary company, which is not included as a rate base account. The normalized coal cost from Trapper Mine in net power costs includes O&M costs but does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine net plant investment to rate base in order for the Company to earn a return on its investment. This treatment is consistent with Docket No. 99-035-10 and the Company's general rate cases since that time.

Jim Bridger Mine Rate Base (page 8.3) – The Company owns a two-thirds interest in the Bridger Coal Company, which supplies coal to the Jim Bridger generating plant. The Company's investment in Bridger Coal Company is recorded on the books of Pacific Minerals, Inc. Because of this ownership arrangement, the coal mine investment is not included in electric plant in service. This adjustment is necessary to properly reflect the Bridger Coal Company investment in rate base in order for the Company to earn a return on its investment. The normalized coal costs for Bridger Coal Company in net power costs include the O&M costs of the mine but provide no return on investment. This treatment is consistent with Docket No. 97-035-01 and the Company's general rate cases since that time.

Environmental Settlement – PERCO (page 8.4) – In 1996, the Company received an insurance settlement of $33 million for environmental clean-up projects. These funds were transferred to a subsidiary called PacifiCorp Environmental Remediation Company ("PERCO"). This fund balance is amortized or reduced as PERCO expends dollars on clean-up costs. PERCO received an additional $5 million of insurance proceeds plus associated liabilities from Rocky Mountain Power in 1998. This adjustment includes the unspent insurance proceeds in results of operations as a reduction to rate base.

Customer Advances for Construction (page 8.5) – Customer advances for construction are booked into FERC Account 252. When they are booked, the entries do not reflect the proper allocation. This adjustment corrects the allocation of customer advances for construction in the account.

Customer Service Deposits (page 8.6) – Utah requires the Company to include customer service deposits as a reduction to rate base. This adjustment reflects the deposits in results as a rate base deduction and also includes the interest paid on the customer service deposits in expense. This treatment was stipulated in Utah Docket No. 97-035-01 and has been upheld in subsequent dockets.

Miscellaneous Rate Base (page 8.7) – This adjustment includes four parts as described below:

- Cash is removed from rate base to avoid earning a rate of return on the balance.
- The cost of the Company's coal plant fuel stock is increasing due to increases in the cost of coal and the number of tons stored at each site. This adjustment reflects the increase in the fuel stock balance into results.
- In order to avoid earning a double return on rate base, the Company is adjusting the prepaid overhaul balances in FERC Account 186 for the Lake Side and Chehalis gas plants to reflect the transfer of prepaid overhaul costs into plant in service as of July 2009 and October 2009, respectively.
- This adjustment revises the Chehalis rate base balance in FERC Account 102 to remove amounts related to asset retirement obligation timing and a payment to the Energy Facility Site Evaluation Council in Washington that has not yet been made. As of December 2008 the Company was awaiting approval from FERC before transferring Chehalis related

balances to the various FERC accounts where they will reside permanently.

Powerdale Hydro Removal (page 8.8) – Powerdale is a hydroelectric generating facility located on the Hood River in Oregon. This facility was scheduled to be decommissioned in 2010; however, in 2006 a flash flood washed out a major section of the flow line. The Company determined that the cost to repair this facility was not economical and determined it was in the ratepayers' best interest to cease operation of the facility.

In Docket No. 07-035-14, the Company requested permission to transfer the net book value, including an offset for insurance proceeds, of the assets to an unrecovered plant regulatory asset and asked the Commission to establish an amortization period for the asset. In that Docket, the Commission authorized the Company's request regarding the unrecovered pant and also allowed the Company to defer future decommissioning costs to a regulatory asset. In the order for Docket No. 07-035-93, the Commission further specified that the regulatory asset for the decommissioning costs could be amortized over three years beginning January 1, 2008. This adjustment reflects the plant balances and amortization expense in the Test Period consistent with the previous Commission orders.

Goose Creek Transmission (page 8.9) – On April 1, 2008, the Company sold its undivided interest in 13.85 miles of transmission line, running from the Company's Goose Creek switching station and extending north to the Decker 230 kV substation near Decker, Montana. The assets sold included structures, miscellaneous support equipment, easements, and rights-of-way associated with the transmission line. The sale of the transmission line resulted in the Goose Creek switching station no longer being needed or useful to the Company. The Company plans to remove the Goose Creek switching station including all above ground facilities. The stipulation approved by the Commission in Docket No. 08-035-38 states that "the Company may write off Utah's portion of the Goose Creek regulatory liability." This adjustment reduces rate base by the net book value of a remaining future asset retirement and also removes the property sale gain from results as allowed in the stipulation. Depreciation expense booked in the twelve months ended December, 2008 is removed in Adjustment 6.1.

Pro Forma Plant Additions (page 8.10) – To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be completed by the end of the Test Period. Company business units identified capital expenditures that will be used and useful prior to the end of the Test Period. Additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. The accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements as described earlier in the depreciation section.

The Company intends to utilize a major plant addition case to seek recovery for two projects that are scheduled to be placed into service prior to June 2010: the Ben Lomond to Terminal transmission line segment set to be placed in service June 2010, and the Dave Johnston scrubber project set to be placed in service May 2010. These projects have not been included in this case.

Plant Retirements (page 8.11) – Composite plant retirement rates were applied to pro forma plant balances included in this filing to reflect ongoing asset retirements through the Test Period. This adjustment reflects these retirements into results for the gross electric plant in service. A corresponding entry to accumulated depreciation and amortization is included in the calculation of Test Period reserve balances in Adjustment 6.2.

Reduction to Generation Plant Additions (page 8.12) – This adjustment reduces the amount of generation capital additions to be included in the rate case. After the detailed capital additions were compiled during the preparation of this case, the Company reduced the amount of capital additions planned for the Test Period. This adjustment will bring the total capital additions included in the case in line with the current projected level.

Plant Held for Future Use (page 8.13) – The Company has deemed that the construction of a new 138 to 12.5 kV substation is necessary and has been approved for construction due to the overall load growth in the Herriman, Utah area. Preliminary survey & investigation charges related to the construction of the transmission line to the substation need to be reflected in results of operation. This adjustment re-allocates the balance as of December 2008 of Herriman project costs from FERC Account 183, which is not included in rate base, to FERC Account 105, plant held for future use, to allow for recovery of these costs.

Q. Please describe the remaining sections of the Report.

A. Tab 9 Rolled-In recasts Tab 2 based on the Rolled-In allocation methodology. This information is being provided pursuant to the Commission order from the application of the Company for an investigation of inter-jurisdictional issues in Docket No. 02-035-04. Tab 10 Allocation Factors contains the detailed derivation of the jurisdictional allocation factors using the Revised Protocol allocation methodology.

Q. How have changing jurisdictional loads impacted the allocation factors in this case?

A. As discussed by Dr. Eelkema, Utah loads for this case are slightly lower than in the 2008 general rate case (Docket 08-035-38). This load change, along with revised load forecasts for other PacifiCorp states have been incorporated into the allocation factors used in this case.

Q. Does this conclude your direct testimony?

A. Yes.