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UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-07-05**
MOUNTAIN POWER FOR	)	
APPROVAL OF CHANGES TO ITS	)	**Direct Testimony of Steven R. McDougal**
ELECTRIC SERVICE SCHEDULES	)	
	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-07-05

June 2007

Q. Please state your name and business address.

A. My name is Steven R. McDougal and my business address is 201 South Main, Suite 2300, Salt Lake City, Utah, 84111.

QUALIFICATIONS

Q. What is your current position and your employment history at the Company (also referred to as Rocky Mountain Power)?

A. I am currently employed as the Director of Revenue Requirements for Rocky Mountain Power. I have been employed by the Company since 1983. My experience includes various positions within the regulation, finance, resource planning, business planning and internal audit departments.

Q. What are your responsibilities as Director of Revenue Requirements?

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 the explanation of those calculations to regulators in the jurisdictions in which the Company operates.

Q. What is your educational background?

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.

Q. Do you hold any professional licenses?

A. Yes. I am a Certified Public Accountant (CPA) and also a Certified Internal Auditor.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony before the Washington Utilities and Transportation Commission and the California Public Utilities Commission.

PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. My direct testimony addresses the calculation and need for the $18.5 million increase requested in the Company's application. In support of this calculation, I address the following issues:

- A summary of the calculation of the $18.5 million requested rate increase.
- A description of the test period used in this case, which is twelve months ending December 31, 2006 with known and measurable adjustments through December 31, 2007.
- The Idaho revenue requirement calculation and revenue increase, including:
    - 2006 actual results of operations.
    - Adjustments to 2006 results of operations.
    - Allocation methodology used.
- The treatment of applicable commitments made as a condition for approval of MidAmerican Energy Holdings Company's (MEHC) acquisition of PacifiCorp (Case No. PAC-E-05-08), including amounts deferred as previously authorized by the Idaho Public Utilities Commission (Commission)

in Case No. PAC-E-06-05.

- Other deferred accounting adjustments / amortizations included in the test period for the removal from service of the uncollectible loans made to Grid West, decommissioning of the damaged Powerdale hydroelectric facility, and MEHC transaction-related severance costs.

REQUIRED RATE INCREASE

Q. What price increase is required to achieve the requested return on equity in this case?

A. Presented as an attachment to my testimony is the Company's Idaho Results of Operations for the twelve months ended December 31, 2006 normalized through December 31, 2007, labeled as Exhibit No. 11. My testimony presents evidence that, based on its results of operations for this test period, Rocky Mountain Power earned an overall return on equity (ROE) in Idaho of 5.3 percent for the twelve-months ended December 2006 as adjusted. This return is less than the ROE currently authorized by the Commission and is less than the return recommended in Dr. Sam Hadaway's testimony to provide a fair and equitable return for the Company's shareholders. An overall price increase of $22.0 million is required to produce the 10.75 percent ROE requested by the Company in this proceeding.

Q. Is the Company requesting the full $22.0 million required to earn a 10.75 percent ROE?

A. No. The Company has reflected the rate mitigation cap as stipulated and approved by the Commission in Case No. PAC-E-02-3. The stipulation states:

"For all Idaho general rate proceedings initiated after the effective date of

> this Stipulation and Revised Protocol, and until March 31, 2009, the Company's Idaho revenue requirement to be used for purposes of setting rates for Idaho customers will be the lesser of: (i) the Company's Idaho revenue requirement calculated under the Rolled-In Allocation Method multiplied by 101.67 percent, or (ii) the Company's Idaho revenue requirement resulting from use of the Revised Protocol."

This adjustment reduces the rate request by $3.6 million to $18.5 million and is shown in Exhibit No. 11 on page 1.0 of Tab 1 Summary.

TEST PERIOD

Q. Please provide an overview of the test period used in this case.

A. The test period for this application is based on the historical twelve-month period ending December 31, 2006 which has been adjusted for known and measurable adjustments through December 31, 2007. This test period is consistent with past Commission practice as well as Company filings made previously in Idaho.

Q. Is the test period in this case consistent with test periods proposed by the Company in other states?

A. No. The Company has used or proposed forecasted test periods in its most recent general rate cases in Utah, Oregon, California and Wyoming. Rocky Mountain Power will also be proposing a forecasted test period in its next Wyoming case consistent with the stipulation in Wyoming Docket No. 20000-230-ER-05.

Q. Does Rocky Mountain Power prefer a forecasted test period?

A. Yes. A forecasted test period is Rocky Mountain Power's preferred method for filing rate cases. While adjusting a historical test year for known and measurable changes can help to reduce regulatory lag, it does not fully match the costs the Company expects to incur to the revenue received once new rates are in effect. Forecasted rate cases match revenues and expenses, help reduce or eliminate regulatory lag, and provide a better estimate of the Company's revenue requirement during the rate effective period. Additionally, during a period of significant capital additions, a forecast test period is critical to maintain the financial stability of the Company.

Q. Why is it important that the test period and the rate effective period be closely aligned?

A. One of the important underlying principles of fair utility rate-making is to match capital investment and prudent expenses with revenues under conditions the utility expects to experience in a normal operating environment. The capital investment, prudent expenses, and revenues that are used to determine the utility revenue requirement are calculated using a "test period." The time period and conditions that the utility will actually experience when rates are in effect are referred to as the "rate effective period." To the extent possible, the rate effective period and the test period should closely match each other. Ideally, new rates should take effect on the commencement of the test year. Traditional historical test periods will never match the rate effective period and, as I discuss later in my testimony, will result in the utility under-earning when it is experiencing rapid expansion and rate base growth. The use of a forecast test period is necessary for Rocky Mountain Power if it is expected to have a reasonable opportunity to earn its authorized rate of return.

Q. What is the effective date of new rates requested in this application?

A. The Company is requesting that new rates from this application become effective January 1, 2008.

Q. If the new rates resulting from this case become effective January 1, 2008, will the test period and the rate effective period coincide?

A. No. The test period is based on December 31, 2006 results with adjustments through December 31, 2007. If new rates become effective January 1, 2008, there will be at least twelve months of regulatory lag built into the Company's Idaho revenue requirement that could financially harm the Company.

Q. Please explain what you mean by the term "regulatory lag."

A. The phrase "regulatory lag" refers to the time between when costs are measured for the utility's revenue requirement and when those costs are recovered in rates as the utility provides service to its customers. More than anything else, regulatory lag is the result of the rate-making process, and all of the incremental steps that go into developing, proposing, challenging, litigating and approving rates for a regulated public utility.

Q. Why is regulatory lag a problem?

A. Regulatory lag is a serious problem when a utility faces a steady upward trend in costs and investments for the foreseeable future, but rates are authorized based on historical costs.

Exhibit No. 12 is a graphical representation of regulatory lag. This Exhibit compares a historical base period, January 1, 2006 through December 31, 2006, the adjustments included through December 31, 2007, and the rate effective period, January 2008 through January 2009. This exhibit highlights the mismatch in investments, operating costs, revenues and loads between the two example test periods and the rate effective period.

Q. Why does Rocky Mountain Power advocate the use of forecasted test period in rate case proceedings?

A. Rocky Mountain Power is in the middle of a period of increasing energy-related costs coupled with substantial new investments being made by the Company to serve customer energy demands. As a result, basing rates on a test period that doesn't reflect the cost to serve customers during the rate effective period effectively denies the Company a reasonable opportunity to earn the return authorized by the Commission.

The Company expects a significant amount of growth across our system over the next several years. The need to serve this growing load has required the Company to acquire new generating resources, some of which are being reflected in rates for the first time in this case. This filing includes 534 megawatts of additional production capacity at the Lake Side generating facility, as well as three new wind projects, the Leaning Juniper, Marengo, and Goodnoe Hills projects, which add a total of 335 megawatts of capacity. Significant new investments in transmission and distribution systems are required to integrate these new resources and ensure continued reliability. Net power costs continue to escalate as a result of increasing fuel costs, purchased power and load growth.

When operating costs and investments in new plant are stable the use of a historic test period may be a reasonable regulatory approach, but only a forecast test period can fully capture the impacts of growing customer load, the dramatic increases in capital investment required to serve it, and the operation and maintenance costs required to maintain system safety and reliability. The use of a forecast test year is the best method for the Company to properly reflect for rate-setting purposes the costs the Company will incur in the rate effective period to provide the level of service our customers demand and deserve.

Q. What does the Company want the Commission to consider in relation to the use of forecasted test periods?

A. The Company respectfully requests that the Commission allow Rocky Mountain Power in future rate cases to use fully forecasted test periods that match the costs and revenues during the rate effective period. As such, the Company requests that a process be established to discuss the use of forecasted test periods with interested parties in Idaho.

REVENUE REQUIREMENT CALCULATION

Q. Please describe Exhibit No. 11.

A. Exhibit No. 11, which was prepared under my direction, is Rocky Mountain Power's Idaho Results of Operations Report (the Report). The Report is based on historical data for the twelve-months ended December 31, 2006, which has been normalized based on known and measurable changes through December 31, 2007. The Report provides totals for revenues, expenses, depreciation, net power costs, taxes and rate base, from both a total-company perspective and as allocated to the Company's Idaho jurisdiction. The Report presents operating results for the period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit No. 11 is organized.

A. Tab 1 Summary is the Idaho allocated results based on the Revised Protocol allocation methodology. Page 1.0 details the calculation of the rate mitigation cap which lowers the rate request by $3.6 million.

Column (1) Total Adjusted Results on Page 1.1 is the Idaho results of operations for the Test Period and shows the current Idaho earnings. The Total Adjusted Results column is carried forward from the results of operations summary, Page 2.2, and shows Idaho's ROE at 5.3 percent. Column (2) Price Change indicates that a revenue increase of $22.0 million is required to raise the return on equity from 5.3 percent to 10.75 percent in Idaho. Column (3) Results with Price Change reflects the Idaho adjusted revenue requirement with the $22 million price increase included. Page 1.2 of Tab 1 supports the calculation of additional revenue-related uncollectible expense associated with the price change requested in column 2 and the net-to-gross bump up percent. Page 1.3 details the calculation of the net operating income percentage. Page 1.4 starts with Idaho unadjusted results and summarizes the impact of the normalization adjustments by type.

Rocky Mountain Power summarizes adjustments into three different types. Type I adjustments represent base period accounting or Commission-ordered adjustments (i.e., reversing one-time write-offs). Type II adjustments typically annualize events that occurred during the base year (i.e., contract changes or wage increases). Type III adjustments reflect known and measurable events occurring in the twelve months following the base period. Page 1.5 is a summary of all the normalizing adjustments by category contained in Tabs 3 through 8.

Tab 2 details Total Company and Idaho allocated results based on the Revised Protocol allocation methodology. Pages 2.3 through 2.39 contain revenues, expenses and rate base detail by FERC account. The Adjusted Total Column of the results on page 2.2 reflects the costs, revenues and rate base that have been calculated as described later in my testimony.

The normalizing adjustments made to actual period data to reflect on-going costs of the Company are described in Tabs 3 through 8. Tab 9 is a restatement of Tab 2 Idaho results using the Rolled-In allocation method instead of the Revised Protocol allocation method. The Tab 9 results are used to calculate the rate mitigation cap adjustment on page 1.0. Tab 10 contains the calculation of the Revised Protocol allocation factors.

Q. Please describe some of the key areas where the Company has experienced cost increases driving the need for the requested price increase.

A. Rocky Mountain Power has incurred increases in two main areas to serve its Idaho customers: (1) new plant investment and the associated operation, maintenance and depreciation costs, and (2) net power costs to serve retail load.

The Company continues to make significant investments to serve its customers adding over $1.8 billion of plant since the Company's last Idaho filing in Case No. PAC-E-06-04. Consequently, Idaho's allocated net rate base has increased by $51 million. This additional plant has also increased Idaho's depreciation expense by approximately $2 million and incremental operation and maintenance costs by $653,000. As I mentioned earlier a significant portion of these plant increases are associated with the new combustion cycle and wind generation plants the Company is adding to meet retail load requirements. The justification for these new resources is explained in the testimony of Company witness William J. Fehrman.

Net power costs continue to increase due to a combination of increasing fuel costs, purchased power and customer load growth. Net power costs in Docket No. PAC-E-06-04, were filed at $685 million compared to $861 million requested in this application. Details supporting the calculation of net power costs are provided in the testimony of Company witness Mark Widmer.

REVENUES

Q. Please describe the revenue normalizing adjustments made in Tab 3, Revenue Adjustments.

A. Page 3.0 of tab 3 is a summary of all the adjustments in Tab 3, listing each in a separate column itemizing the impact to revenue and rate base. The adjustments made to normalize test period revenue are detailed on lead sheets 3.1 through 3.6 with supporting documentation. I will briefly describe each of these adjustments.

Temperature Normalization (page 3.1) – Normalizes the revenue by comparing actual load to temperature normalized load. Weather normalization reflects weather or temperature patterns which were measurably different than normal, as defined by using thirty-year historical averages prepared by the National Oceanic & Atmospheric Administration. Only residential and commercial loads are adjusted for temperature. Since weather during the base period was slightly more extreme than average, the adjustment reduces Idaho revenue by $1,778,856. This adjustment to revenues corresponds to the temperature adjustment made to system peak and energy loads.

Effective Price Change (page 3.2) – This adjustment has two components:

1) The Company is continuing to eliminate Schedule 19. This adjustment includes annual revenues of Schedule 19 customers who bill cheaper on Schedule 6 or 23.
2) Schedule 401 had a rate change effective September 1, 2006, that has been annualized in the results of operations.

These two items combined increase revenues by $91,557.

Revenue Normalization (page 3.3) – This adjustment normalizes base year revenue by removing items that should not be included to determine retail rates, such as credits from the Bonneville Power Administration (BPA). The expense side of the BPA credit is removed in adjustment 5.6. Another element is a pro-forma price change for Schedule 400 and Schedule 10 which was effective January 1, 2007. The combined result of these elements totals a revenue increase of $41,131,903.

SO2 Emission Allowances (page 3.4) – The Company has excess SO2 allowances which it periodically has the opportunity to sell. This adjustment reflects actual sales through March 2007 and planned sales through December 2007. The Company amortizes these sales over a fifteen-year period to closer match the revenues with the plant that generated them. This adjustment reverses the actual sales booked during the test period and replaces those with the corresponding amortization. The unamortized balance is included as a reduction to rate base. This amortization increases Idaho revenues by $172,909 and reduces rate base by $1,458,728.

Revenue Correcting Entries (page 3.5) – The jurisdictional assignment of general business revenues is determined by profit centers within the Company's accounting system. The Company has profit centers that cross state borders in California, Oregon, and Washington, and the assignment of revenues booked to those profit centers currently requires a manual adjustment. This adjustment corrects the jurisdictional assignment and does not impact Idaho results. In addition, some other electric revenues were assigned incorrect allocation factors in 2006 unadjusted results. This adjustment corrects these allocation factors, increasing Idaho revenues by $994,639.

Wheeling Revenues (page 3.6) – In calendar year 2006 the Company was able to collect some outstanding accounts receivable for service provided in prior years. Also, several contract agreements were terminated and are not expected to be to be renewed. These transactions are removed to reflect an on-going level of wheeling revenues in the test period, reducing Idaho's allocation of wheeling revenues by $325,262.

Q. Are there additional adjustments to revenue that are included in other portions of Exhibit No. 11?

A. Yes. The following adjustments are categorized as adjustments to net power costs, but both affect revenue allocated to Idaho. Both of these adjustments are explained further in the net power costs section of my testimony.

Net Power Cost Adjustment (page 5.1) – A portion of this adjustment aligns wholesale sales to the results generated in the GRID model. Company witness Mark Widmer explains how these sales were calculated in his testimony.

James River & Little Mountain Offset (page 5.5) – This adjustment includes a revenue offset to the cost of power purchased based on contractual terms.

OPERATION, MAINTENANCE (O&M), ADMINISTRATIVE & GENERAL (A&G) EXPENSES

Q. Please describe Tab 4 O&M Adjustments?

A. Pages 4.0 through 4.0.2 summarize each adjustment in Tab 4, listing each in a separate column itemizing the impact to expense and rate base. The adjustments made to normalize test period expense are detailed on pages 4.1 through 4.19. The lead sheet of each adjustment is organized by FERC account, dollar amount and allocation factor, along with a brief description of the adjustment. Any applicable supporting documentation is provided behind the lead sheets.

Q. Are labor-related expenses treated differently than non-labor costs?

A. Yes. Labor-related expenses (wages, incentives, pension and benefits) are identified and analyzed separately from non-labor costs. Wages are refined further to identify individual labor groups. Wage increases based on union contracts are applied to the corresponding union group and actuarial studies are utilized to determine the appropriate expense level for pensions and employee benefits. Page 4.5.1 of my exhibit describes the process used to normalize wage and benefit costs in further detail in the report.

Q. Please explain the adjustment to wages and benefits summarized on lead sheets 4.2 through 4.5.

A. Pages 4.2 through 4.5 calculate the normalized level of wages and benefits expected during the test period. The calculations include increases for employee salaries and medical benefits and decreases to incentive and pension costs. The net change in these four tabs increases jurisdictional expense by $920,331.

Q. Was an adjustment made to the annual incentive plan payout?

A. Yes. The Company's Annual Incentive Plan provides performance awards based on the following: achieving individual and group goals including safety goals, individual performance, and success in addressing new issues and opportunities that may arise during the course of the year. The details of the plan and justification for the expected annual payout are provided in the testimony of Company witness Erich Wilson. To align incentive pay included in this application to the level expected on an on-going basis, the annual expense is reduced from $34 million to $27.5 million.

Q. Were employee pension and benefit costs adjusted in this section also?

A. Yes. Consistent with other categories, pension and benefits are itemized starting with actual results and walked forward through December 2007. Pension and other post-retirement benefit costs are decreasing over $5 million. Medical and other employee benefits expenses are increasing $18.3 million. These amounts are supported in the testimony of Company witness Erich Wilson.

Q. Does this labor-related section cover any other items?

A. Yes. Payroll taxes are updated to capture the impact of the changes to employee salaries. This is calculated by applying the FICA tax rates to the net change in salaries.

Q. How are adjustments to labor expenses incorporated into the O&M Summary?

A. After adjusting employee salaries and benefits, the costs are spread back to FERC accounts based on the same percentage that existed in the base period. Pages 4.5.11-13 contain a summary of this spread.

Q. Please explain the remaining adjustments to operation and maintenance expense.

Miscellaneous General Expense (page 4.1) – This adjustment removes from results of operation $24,047 of miscellaneous expenses that should have been charged to non-regulated accounts and excluded from the revenue requirement calculation. Included are Blue Sky program expenses, donations to community and local events, and Klamath ranch management expenses.

International Assignees (page 4.6) – The International Assignee adjustment removes costs associated with former employees on international assignments from Scottish Power. These costs were incurred prior to the MEHC transaction which was finalized March 21, 2006. Since these costs are not ongoing they are removed from results, reducing expense by $17,198.

Removing Non-Recurring Expense (page 4.7) – Four adjustments are made to remove either one-time or out-of-period transactions included in the base period results. This adjustment removes $354,279 associated with the following transactions:

- A right-of-way settlement for past use related to the Crow tribe.
- A settlement accrual associated with the 2003 Utah winter storm.
- MEHC transaction and Rocky Mountain Power re-branding expenses.
- Blue Sky funded solar panels at the Salt Palace.

Memberships & Subscriptions (page 4.8) – This adjustment reduces expense by $40,623 to reflect discontinuance of the Company's membership in Edison Electric Institute and partial removal of industry trade membership fees that might be used for political purposes. The adjustment removes 25 percent of membership fees at Pacific Northwest Utility Conference Committee, Utility Air Regulatory Group, Western Energy Institute and other trade organizations.

Power Delivery Programs (page 4.9) – This adjustment reduces operation and maintenance expense by $1,292,550 to align the base period with the anticipated on-going level of expense.

Incremental Generation O&M (page 4.10) – This adjustment adds operation and maintenance expense into the test period to reflect the incremental cost of operating and maintaining new investments in supply-side resources. Expenses are included only for the number of months each resource will be in service prior to December 31, 2007. The adjustment increases Idaho allocated O&M by $653,808.

Irrigation Load Control Program (4.11) – Incentive payments made to Rocky Mountain Power customers participating in the Schedule 72 irrigation load control program were initially system allocated in the unadjusted data. This adjustment corrects that allocation assigning these costs situs to Idaho consistent with other demand side management (DSM) programs.

DSM Amortization Removal (page 4.12) – The Company recovers authorized DSM expenses through a system benefit charge (SBC) tariff rider, Schedule 191. This adjustment removes the related amortization of DSM costs from results to ensure they are not included in the revenue requirement calculation.

Idaho Intervenor Funding (page 4.13) – This adjustment adds the costs associated with Idaho intervenor funding to results, amortizing previously deferred expenses over one year.

Idaho Cash Basis Pension Funding (page 4.14) – The Commission has ordered other in-state utilities to include cash contributions for pension funding in rates rather than their FAS 87 pension accrual. The Company would prefer to include the FAS 87 accrual in rates consistent with treatment in its other jurisdictions. However, given the Commission's direction in other cases, the Company has adjusted its expense level to the cash contribution expected during the test period, increasing Idaho allocated expense by $1,000,086.

Grid West Loan (page 4.15) – This adjustment replaces the accrual for bad debt with the amortization of the loan as approved by the Commission in Order No. 30156, Case No. PAC-E-06-03. The Grid West loan is discussed later in my testimony in the section regarding deferred accounting items.

Postage Increase (page 4.16) - Effective May 14, 2007, the U.S Postal Service increased its rates by $0.02 from $0.29 to $0.31 for utility mailings. This adjustment reflects that additional cost by applying the two-cent increase to the average number of retail customers during calendar year 2006. The adjustment increases Idaho allocated expense by $10,097.

MEHC Transition Savings (page 4.17) – After completion of the MEHC acquisition of PacifiCorp certain cost saving programs were implemented. The major focus was to reduce the amount of corporate overhead by eliminating several employees' positions. Those whose positions were eliminated qualified for a change-in-control (CIC) severance payout based on years of service and salary. This adjustment removes the salary and severance paid to these former employees. Deferral of this severance cost was authorized in the Idaho Public Utility Commission Order No. 30225, Case No. PAC-E-06-11. The Company is proposing a three-year amortization of this deferral and has included one year of amortization expense in this filing. The net impact of this adjustment is to decrease Idaho allocated expense by $2,962,769.

Rocky Mountain Power expects annual savings of $35.4 million related to the MEHC transition related employee reductions. In order to achieve these savings Rocky Mountain Power spent $39.5 million for CIC severance payments. This results in a payback period of less than 15 months. The three-year amortization is proposed as a way of better matching the CIC-related costs to the savings expected from the employee reductions. Page 4.19 described below shows that these employee reductions are not being used to meet the A&G cost commitment included in commitment I31.

MEHC Affiliate Management Fee and Direct Billings Commitment (page 4.18)

This adjustment complies with MEHC acquisition commitments and has two elements. First, MEHC commitment I28 states:

> a) MEHC and PacifiCorp will hold customers harmless for increases in costs retained by PacifiCorp that were previously assigned to affiliates relating to management fees. The total company amount assigned to PacifiCorp's affiliates is $1.5 million per year, which is the amount of the total company rate credit. This commitment expires on December 31, 2010. This Commitment is in lieu of Commitment 38, and a state must choose between this Commitment I 28 and Commitment 38. (The commitment is reflected in Row 2 of Appendix 2.)
>
> b) This commitment is offsetable to the extent PacifiCorp demonstrates to the Commission's satisfaction, in the context of a general rate case the following:
>
> > i) Corporate allocations from MEHC to PacifiCorp included in PacifiCorp's rates are less than $7.3 million;
> >
> > ii) Costs associated with functions previously carried out by parents to PacifiCorp and previously included in rates have not been shifted to PacifiCorp or otherwise included in PacifiCorp's rates; and
> >
> > iii) Costs have not been shifted to operational and maintenance accounts (FERC accounts 500-598), customer accounts (FERC accounts 901-905), customer service and informational accounts (FERC accounts 907-910), sales accounts (FERC accounts 911-916), capital accounts, deferred debit accounts, deferred credit accounts, or other regulatory accounts.

PacifiCorp has only included $7.3 million in this application for management fee billings. (The historical test year includes three months of billings from Scottish Power and nine months from MEHC. However, the total amount of $7.3 million is expected to be the on-going level of annual charges from MEHC.) Since the total charges included in the case are at $7.3 million no additional adjustment was necessary.

MEHC commitment I30 states:

> a) MEHC and PacifiCorp will hold customers harmless for increases in costs resulting from PacifiCorp corporate costs previously billed to PPM and other former affiliates of PacifiCorp. Oregon Commission Staff has valued the potential increase in total company revenue requirement if these costs are not eliminated as $7.9 million annually (total company)

> through December 31, 2010 and $6.4 million annually (total company) from January 1, 2011 through December 31, 2015, which shall be the amounts of the total company rate credit. This commitment shall expire on the earlier of December 31, 2015 or when PacifiCorp demonstrates to the Commission's satisfaction, in the context of a general rate case, that corporate costs previously billed to PPM and other former affiliates have not been included in PacifiCorp's rates. This Commitment is in lieu of Commitment 38, and a state must choose between this Commitment I 30 and Commitment 38.
>
> b) This commitment is offsetable to the extent PacifiCorp demonstrates to the Commission's satisfaction, in the context of a general rate case, that corporate costs previously billed to PPM and other former affiliates have not been included in PacifiCorp's rates.

PacifiCorp has reduced costs and transferred 31 employees to PPM who had been previously charging part of their time to PPM. This will result in annual salary and benefit savings in excess of $6.2 million.

Most of the employee transfers to PPM occurred in 2005. However, $243 thousand related to these transferred employees was in the test period prior to the MEHC transaction. This amount is removed in this adjustment. The remainder of the $7.9 million reduction was achieved through elimination of other corporate costs.

Administrative and General Cost Commitment (page 4.19) - Commitment I31 of the MEHC transaction established a rate credit if the amount of A&G included in the case exceeds a specified level.

> a) MEHC and PacifiCorp commit that PacifiCorp's total company A&G costs as reflected in FERC Accounts 920 through 935 will be reduced by $6 million annually from a baseline amount of $228.8 million. The maximum amount of the total company rate credit in any year is $6 million per year. This commitment expires December 31, 2010. Beginning with the first month after the close of the transaction, Idaho's share of the $0.5 million monthly rate credit will be deferred for the benefit of customers and accrue interest at PacifiCorp's authorized rate of return. This Commitment is in lieu of Commitments 22 and U 23 from the Utah

settlement, and a state must choose between this Commitment I 31 and Commitments 22 and U 23.

b) The credit will be offsetable on a prospective basis, for every dollar that PacifiCorp demonstrates to the Commission's satisfaction, in a subsequent general rate case, that total company A&G expenses included in PacifiCorp's rates (including any adjustments adopted by the Commission to these categories) are less than $6 million above the "Stretch Goal" and have not been shifted to other regulatory accounts. The 2006 Stretch Goal will be $222.8 million. Subsequent Stretch Goals shall equal the 2006 Stretch Goal multiplied by the ratio of the Global Insight's Utility Cost Information Service (UCIS)-Administrative and General – Total Operations and Maintenance Index (INDEX CODE Series JEADGOM), for the test period divided by the 2006 index value. If another index is adopted in a future PacifiCorp case, that index will replace the aforementioned index and will be used on a prospective basis only. If this occurs, the Stretch Goal for future years will equal the Stretch Goal from the most recent full calendar year multiplied by the ratio of the new index for the test period divided by the new index value for that same most recent full calendar year.

The commitment is to reduce A&G expense to $222.8 million on a total-company level. In 2006, actual A&G expenses totaled $239 million; however, after taking normalizing adjustments into account, the test period in this application includes only $208.5 million for A&G expense, well below the $222.8 million specified in the commitment. In addition, pursuant to the Commission order in Case No. PAC-E-06-05, the Company has been deferring Idaho's allocated share of the committed reductions since April 1, 2006, and will continue to defer the credit until new rates are effective that reflect the reduction in A&G expense.

In the MEHC transition deferral case the Commission ordered that Rocky Mountain Power could not use the transition reductions to meet the A&G cost commitment and also request recovery of the CIC related costs (Order No. 30225). The bottom of page 4.19.1 includes a recalculation of the A&G

commitment showing that absent the MEHC transition-related savings included on page 4.17 the A&G expenses would have been $211.3 million, which is also below the $222.8 million commitment level. This shows that Rocky Mountain Power was significantly below the A&G commitment even without the savings associated with the transition-related employee reductions.

Q. Are there additional cost changes expected as a result of the MEHC transaction?

A. Yes. The commitments to accelerate distribution circuit fusing and continue the Saving SAIDI program, as agreed in general commitment 35, are expected to increase expense. The distribution circuit fusing program is expected to increase costs by $1.5 million per year for five years. The Saving SAIDI initiative will be extended for three years at an additional cost of $2 million annually. However, additional cost savings from these two programs are expected to offset the expense.

Net Power Costs

Q. Please explain the adjustments to power costs.

A. **Net Power Cost Adjustment (page 5.1)** – This adjustment normalizes power generation, fuel, purchased power, wheeling expense, and sales for resale based on normal hydro and weather conditions and in a manner consistent with the contractual terms of the Company's sales and purchase agreements. The calculation of net power costs is explained in detail in Company witness Mark Widmer's testimony.

Trail Mountain Closure (page 5.2) – The Trail Mountain Mine was used to