

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

3 A. My name is Steven R. McDougal, and my business address is 201 South Main,  
4 Suite 2300, Salt Lake City, Utah, 84111. I am currently employed as the Director  
5 of Revenue Requirements for the Company.

6 **Qualifications**

7 **Q. Briefly describe your educational and professional background.**

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

16 **Q. What are your responsibilities as director of revenue requirements?**

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

22 **Q. Have you testified in previous regulatory proceedings?**

23 A. Yes. I have provided testimony before the Idaho Public Utilities Commission, the

1 Utah Public Service Commission, the Washington Utilities and Transportation  
2 Commission, the California Public Utilities Commission, the Oregon Public  
3 Utilities Commission, the Wyoming Public Service Commission, and the Utah  
4 State Tax Commission.

5 **Purpose and Overview of Testimony**

6 **Q. What is the purpose of your testimony in this proceeding?**

7 A. My direct testimony describes the calculation of the Company's Idaho revenue  
8 requirement and the rate relief requested, based upon the Company's cost of  
9 service filing. Specifically, I provide testimony on the following:

- 10 • Calculation of the \$32.7 million retail revenue increase requested in this  
11 case, representing the increase over current rates required for the  
12 Company to recover the costs incurred to serve Idaho customers;
- 13 • Inter-jurisdictional allocations, including utilization of 2010 Protocol and  
14 treatment of Idaho's Irrigation Load Control Program costs and other  
15 Class 1 demand side management ("DSM") costs;
- 16 • A description of the Test Period proposed in this case, including the  
17 treatment of rate base and jurisdictional loads;
- 18 • The results of operation for the Test Period, demonstrating that under  
19 current rates the Company will earn an overall return on equity ("ROE")  
20 in Idaho of 5.3 percent, which is significantly below the return on equity  
21 requested in this case and the current authorized return; and
- 22 • Calculation of the Load Change Adjustment Rate ("LCAR") based on  
23 costs in this filing for use in the Energy Cost Adjustment Mechanism

1 (“ECAM”).

2 In addition to supporting the Company’s revenue requirement, I discuss a number  
3 of items that were addressed by the Commission in Case No. PAC-E-10-07 (the  
4 “2010 General Rate Case”) and explain their treatment in this case. I also describe  
5 two accounting changes included in the Company’s filing: (1) elimination of  
6 captive insurance coverage, replaced with self-insurance accruals on a state  
7 specific basis; and (2) accelerated depreciation of certain hydro generation  
8 facilities on the Klamath river. My testimony is accompanied by various  
9 supporting exhibits including the results of operations for the Company’s  
10 proposed 2011 test period based on calendar year 2010 data, adjusted for known  
11 and measurable changes through December 31, 2011.

12 **Revenue Increase**

13 **Q. What is the revenue increase necessary to achieve the requested return on**  
14 **equity (“ROE”) in this case?**

15 A. Utilizing Dr. Samuel C. Hadaway’s recommended ROE of 10.5 percent produces  
16 an overall Idaho revenue requirement of \$250.9 million. When compared to retail  
17 revenue at present rates an overall revenue increase of \$32.7 million is needed for  
18 the Company to achieve its recommended return. Exhibit No. 2 also shows that  
19 without a rate increase Rocky Mountain Power will earn an ROE of 5.3 percent in  
20 Idaho during the Test Period. This return is far less than the 9.9 percent authorized  
21 by the Commission in the 2010 General Rate Case and the 10.5 percent ROE  
22 requested in this case.

23 Idaho’s jurisdictional revenue requirement is determined based on the

1 2010 Protocol allocation methodology, which is currently being considered by the  
2 Commission. Exhibit No. 1 provides a summary of Idaho-allocated results of  
3 operations for the Test Period, and details supporting the revenue requirement by  
4 FERC account are provided in Exhibit No. 2.

5 **Q. Please explain the main drivers causing the need for a rate increase.**

6 A. Two main drivers are causing the need for a revenue increase in this case: net  
7 power costs and capital investment. As a regulated utility the Company must  
8 serve existing, and reasonably anticipated customer loads. It must also comply  
9 with environmental and other regulatory and statutory requirements regarding  
10 production and transmission facilities. The actions that are taken by the Company,  
11 in this regard, are guided by the standard of “risk-adjusted least-cost,” over the  
12 term of the action or investment. This means that the Company will weigh all  
13 legally mandated requirements against its obligation to provide service to the  
14 greatest extent possible at the least cost.

15 Company witness Mr. Gregory N. Duvall describes the increases in  
16 system-wide net power costs. The Company’s application seeks to increase net  
17 power costs from \$1.025 billion to \$1.312 billion, which will also become the  
18 base net power costs tracked in the Company’s ECAM in the future. Company  
19 witness Mr. Darrell T. Gerrard testifies regarding the transmission investments  
20 that have been made to serve customers. Company witnesses Ms. Cathy S.  
21 Woollums and Mr. Chad A. Teply testify regarding significant generation  
22 resource investments that have been required to satisfy environmental  
23 requirements as well as investments that have been made to improve the

1 efficiency of some units. My testimony addresses the revenue requirement impact  
2 of these major projects and that of other investments across the Company.

3 **Inter-jurisdictional Allocations**

4 **Q. What methodology did the Company use to calculate the Idaho-allocated**  
5 **revenue requirement in this case?**

6 A. The Company's requested price increase is calculated using the 2010 Protocol  
7 inter-jurisdictional allocation that is currently before this Commission for  
8 approval in Case No. PAC-E-10-09 (the "2010 Protocol Case"). The 2010  
9 Protocol contains proposed amendments to the Revised Protocol resulting from  
10 collaboration with multiple stakeholders through the Multi-State Process ("MSP")  
11 Standing Committee, the group tasked with evaluating the continued use of the  
12 Revised Protocol for setting rates.

13 **Q. What is the status of the Company's application for approval of the 2010**  
14 **Protocol?**

15 A. The Company filed its application on September 15, 2010, and the Case remains  
16 open for Commission consideration. On March 30, 2011, Commission Staff filed  
17 comments supporting approval of the 2010 Protocol, with the condition that the  
18 Idaho Irrigation Load Control Program be treated consistent with the  
19 Commission's order in the Company's 2010 General Rate Case.<sup>1</sup>

20 The Company filed reply comments on April 15, 2011, agreeing to the  
21 Staff position, and the Company's filing in this general rate case is made  
22 consistent with Staff's comments. However, because the Commission has not yet

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<sup>1</sup>Monsanto also filed comments on March 30, 2011.

1 approved the 2010 Protocol, the Company's filing in this case may need to be  
2 updated to reflect the final outcome of the 2010 Protocol Case.

3 **Q. What are the direct impacts on this case related to the 2010 Protocol?**

4 A. There are three main impacts in this case. First, the scope of the Embedded Cost  
5 Differential ("ECD") is reduced and is now a fixed amount rather than changing  
6 with each set of results. Second, seasonal allocation of certain resources is  
7 eliminated. Third, state income taxes are calculated for each jurisdiction using the  
8 weighted statutory state tax rate rather than allocated using the Income Before  
9 Tax ("IBT") allocation factor. As agreed to in the Company's reply comments in  
10 the 2010 Protocol Case, Tabs 11 and 12 of Exhibit No. 2 provide the test period  
11 results using the Revised Protocol and Rolled-In allocation methodology for  
12 comparison purposes.

13 **Q. Please describe the treatment of Class 1 DSM programs in this rate case.**

14 A. In this case, the Company is treating all Class 1 DSM programs consistent with  
15 Order No. 32196 from the 2010 General Rate Case, wherein the Commission  
16 ruled that the costs associated with the Idaho Irrigation Load Control Program be  
17 system allocated. The Company currently runs three programs that are classified  
18 as Class 1 DSM programs: the Idaho Irrigation Load Control Program, the Utah  
19 Irrigation Load Control Program, and the Utah Cool Keeper program. In previous  
20 Idaho filings, the Company treated these programs as situs resources to their  
21 respective state.

1 **Q. Please describe the treatment of the Company’s Class 1 DSM programs**  
2 **proposed as part of the 2010 Protocol methodology.**

3 A. As part of the Company’s 2010 Protocol filing, and consistent with the filings in  
4 Utah, Oregon and Wyoming, the Company proposed treating all Class 1 DSM  
5 programs as situs, identical to their treatment under the previously approved  
6 Revised Protocol. However, Staff’s comments in that Case state that “to be  
7 consistent with Order No. 32196 in Case No. PAC-E-10-07, Staff recommends a  
8 deviation be included in the Idaho Order for the system allocation of these costs.”  
9 Thus, the Company is treating all Class 1 DSM programs, including the Idaho  
10 Irrigation Load Control Program, as system resources in this filing.

11 **Q. Have other states agreed to treat Class 1 DSM programs as system**  
12 **resources?**

13 A. No. Commission Staff has raised this issue to the MSP Standing Committee, and  
14 the issue is being discussed between the states. Company filings in other states  
15 continue to treat Class 1 DSM programs as situs DSM programs pending a  
16 resolution of the issue. However, as part of the 2010 Protocol settlements in  
17 Oregon and Wyoming, language was included referring to the ongoing MSP  
18 discussions on the topic. The Wyoming 2010 Protocol stipulation states:

19 The Parties agree that the emerging issues related to the allocation  
20 of Class 1 DSM programs are not yet ripe for Commission action.  
21 The Parties agree that additional analysis and discussion of these  
22 issues should be undertaken in the MSP Standing Committee  
23 workgroup, and the Parties will endeavor to participate in the  
24 workgroup efforts to the extent possible, subject to the availability  
25 of resources. The Parties shall encourage the workgroup to develop  
26 a proposed resolution on these issues by the next MSP  
27 Commissioners’ Forum. The Parties understand that the Company

1                    may make a subsequent filing with the Commission to address this  
2                    discrete issue.<sup>2</sup>

3    **Q.    Where is the system treatment of Class 1 DSM programs reflected in the**  
4                    **Company’s revenue requirement calculation?**

5    A.    There are two components of the Class 1 DSM programs that are reflected in the  
6                    Company’s revenue requirement, the costs and the benefits of the programs. The  
7                    costs of the Class 1 DSM programs consist of the administrative costs of running  
8                    the program and the credits paid to the participants of the program. On page 4.4 of  
9                    Exhibit No. 2 these costs are shown to be included in the results of operations on  
10                    a system (“SG”) factor. On an actual basis, the benefits of the Class 1 DSM  
11                    programs occur in the load reductions by state as a result of program operation.  
12                    The 2010 coincident peaks in the filing were adjusted to reflect system treatment  
13                    of the load curtailments from the Class 1 DSM programs, i.e. jurisdictional load  
14                    does not include reductions in load caused by operating the programs in 2010.  
15                    Reductions in peak loads due to the programs operating at time of system  
16                    coincident peak were added back to the relevant jurisdictions so that the  
17                    jurisdictions do not receive the full benefits of the program while other states pay  
18                    for the costs. The calculation of the coincident peaks can be viewed in Exhibit No.  
19                    2 on page 10.13. Further discussion regarding the loads used in this filing is  
20                    provided later in my testimony.

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<sup>2</sup>Wyoming Public Service Commission Docket No. 20000-381-EA-10, Record No. 12624, Stipulation and Agreement paragraph 21, March 25, 2011

1 **Test Period**

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

4 A. The Company used the historical results of operations for the 12-month period  
5 ended December 31, 2010, adjusted for known and measurable changes through  
6 December 31, 2011 (the “Test Period”). As I will discuss later in my testimony,  
7 rate base is included using the end of year balances.

8 **Q. Is the Test Period in this case consistent with test periods used by the**  
9 **Company in previous Idaho general rate cases?**

10 A. Yes. The Test Period is prepared in a manner that is consistent with past  
11 Commission practice and the Company’s general rate cases filed previously,  
12 including the Company’s last two general rate cases, Case Nos. PAC-E-08-07 and  
13 PAC-E-10-07. The Company uses historical data and adjusts it for known events  
14 and costs or normalizes the data to reflect a test period that is as reflective as  
15 possible of the rate effective period given Idaho test period treatment.

16 **Q. What overriding principle guided the Company’s development of the Test**  
17 **Period in this case?**

18 A. The primary objective in determining a test period is to develop normalized  
19 results of operations which best reflect the operating conditions during the time  
20 that new rates will be in effect (the “rate effective period”). Because Idaho has  
21 predominantly relied on historical test periods for setting rates, the Company used  
22 historical data with normalizing adjustments through December 2011 to reflect as  
23 closely as possible the rate effective period. Aligning the Test Period and rate

1 effective period is crucial in an environment of rapidly expanding rate base and  
2 increasing net power costs in order to adequately capture the conditions that the  
3 Company will experience in providing safe and reliable electrical service during  
4 the time that service will actually be provided. To better align the Test Period  
5 with the rate effective period, and consistent with past cases and Commission  
6 treatment, the Company has calculated rate base on an end-of-period basis,  
7 including actual rate base at December 31, 2010, plus major capital additions that  
8 will be in service by December 31, 2011, reflected at the additions' full cost.  
9 Expense and revenue items related to new capital additions, including net power  
10 cost impacts, are annualized so that a full year of the cost or benefit is included in  
11 the Test Period.

12 **Q. Does the method the Company used to calculate loads differ from the**  
13 **treatment used in the 2010 General Rate Case?**

14 A. Yes. In its 2010 General Rate Case, the Company found that the metered loads  
15 reflected abnormal operating conditions that occurred in the 2009 calendar year.  
16 Specifically, a sharp reduction in irrigation and tariff contract load that was not  
17 weather related was distorting the loads. Due to this abnormality, loads were  
18 calculated using a forecasted level to better reflect the ongoing load the Company  
19 expected to serve during the rate effective period.

20 **Q. Is this abnormality an issue in the metered loads used in this case?**

21 A. No. The unadjusted loads in this case do not reflect such abnormal operating  
22 conditions as described above. For this reason, the Company used actual metered  
23 loads, adjusted for special contract curtailments, Class 1 DSM programs and

1 weather in its request.

2 **2010 General Rate Case, Order No. 32196**

3 **Q. Please describe how the Company reflected the Commission’s ruling in**  
4 **Order No. 32196 from the 2010 General Rate Case in this filing.**

5 A. Most directives from the Commission’s Order are reflected throughout the  
6 Company’s request. The treatment of a few of those items is highlighted below:

7 **Irrigation Load Control Program Allocation** – As described earlier, the Idaho  
8 Irrigation Load Control Program is treated as a system resource.

9 **Uncollectible Revenues** – Consistent with the Commission’s Order, the  
10 Company adjusted its actual 2010 uncollectible expense to reflect a three-year  
11 historical average. The details of the adjustment are shown in Exhibit No. 2 on  
12 page 4.17.

13 **Outside Services Expense** –The Company adjusted the 2010 outside services  
14 expense to a three-year historical average consistent with the Commission’s  
15 Order. The calculation can be found in Exhibit No. 2 on page 4.18.

16 **Pension Expense** – As directed by the Commission, the Company used a three-  
17 year average of cash contributions to the pension plan. The details of the  
18 calculation are shown on page 4.16 of Exhibit No. 2.

19 **Supplemental Executive Retirement Plan (“SERP”) Costs** – In accordance  
20 with the Commission’s Order, the Company’s request does not contain any costs  
21 related to SERP. The removal of these costs can be viewed in Exhibit No. 2 in the  
22 Company’s Wage and Employee Benefits Adjustment on page 4.3.4 and the  
23 MEHC Management Fee Adjustment on page 4.10.

1 **Q. Is this a complete list of the items from the Commission's Order that were**  
2 **implemented in this Application?**

3 A. No. Several other adjustments ordered by the Commission are included and noted  
4 throughout Exhibit No. 2.

5 **Q. Were there any items addressed by the Commission in its Order in the 2010**  
6 **General Rate Case that the Company did not reflect in this Application?**

7 A. Yes. A few of the items that were addressed by the Commission in the 2010  
8 General Rate Case are not implemented in the Company's Application. For these  
9 specific items, the Company respectfully requests the Commission reexamine  
10 these particular issues within the context of this general rate case and additional  
11 evidence being offered by the company. The impact that each item would have on  
12 the Company's request is provided in Tab 9 of Exhibit No. 2. Each of these items  
13 is listed below with a brief discussion or reference to the appropriate Company  
14 witness.

15 **Idaho Disconnect Policy** – The Company's Idaho disconnect policy is addressed  
16 in the direct testimony of Company witness Ms. Barbara A. Coughlin.

17 **Wage Increases** – The Company's costs associated with wage increases are  
18 discussed in the direct testimony of Company witness Mr. Erich D. Wilson.

19 **Populus to Terminal** – The Populus to Terminal transmission project is  
20 discussed in the direct testimony of Company witness Mr. Gerrard.

21 **Coal Pile Inventory** – This topic is discussed in detail in the direct testimony of  
22 Company witness Ms. Cindy A. Crane.

23 **MEHC Management Fees** – In 2010, the Company booked approximately \$7.5

1 million to regulated accounts for the MEHC management fee. This amount  
2 includes approximately \$200k for SERP costs and \$1.9 million related to the  
3 Annual Incentive Plan (“AIP”) costs paid to employees of PacifiCorp affiliates  
4 and billed to PacifiCorp through the MEHC management fee. In the Company’s  
5 2010 General Rate Case, the Commission approved Staff’s adjustment to remove  
6 costs associated with both SERP and AIP from the MEHC management fee. In  
7 this filing, the Company removed the SERP from the MEHC management fee as  
8 shown in Exhibit No. 2 on page 4.10, but the Company included the AIP in the  
9 MEHC management fee for the Test Period. Company witness Mr. Wilson  
10 provides further support for including these costs in results. The impact of the AIP  
11 as included in the MEHC management fee is shown in Exhibit No 2. on page 9.0.

## 12 **Accounting Changes**

13 **Q. Please explain the Company’s proposed treatment of property and liability**  
14 **insurance.**

15 A. Obtaining insurance through a captive insurance policy at current rates is no  
16 longer an option. The transaction commitment to maintain captive insurance  
17 expired at the end of 2010 and the current policy expires on March 21, 2011. The  
18 captive coverage will be replaced with self-insurance coverage for third-party  
19 liability, transmission and distribution (“T&D”) property, and non-T&D property.  
20 This eliminates the expense for captive insurance premiums and instead provides  
21 an accrual to state specific self-insurance reserves. These self insurance reserves  
22 will cover certain Idaho allocated O&M related damages. Capital related damages  
23 will be recovered as projects are added to rate base, consistent with other capital

1 investments.

2 **Q. What level of coverage was provided by the captive insurance?**

3 A. The coverage under the captive varied by category:

4 • Excess liability insurance provided indemnity for amounts the Company is  
5 legally obligated to pay for damages due to bodily injury, personal injury  
6 or property damage. The captive covered \$750,000 per occurrence, in  
7 excess of a \$250,000 deductible. Commercial insurance covered \$175.0  
8 million per occurrence after a deductible of \$1 million.

9 • T&D property damage insurance covered property damage to overhead  
10 transmission and distribution lines related to both O&M and capital  
11 events. The first \$25,000 damages per event were defined as a deductible  
12 and were allocated to O&M and capital. The captive then covered \$10.0  
13 million annually in excess of an annual \$5.0 million aggregate deductible  
14 (over and above the \$25,000 per-event deductible). There was no  
15 incremental commercial insurance for T&D property damage.

16 • Non-T&D property damage covered all risks of direct physical loss or  
17 damage including boiler explosion, machinery and electrical breakdown,  
18 flood and earthquake. The captive covered \$6.0 million per occurrence, in  
19 excess of a \$1.5 million deductible. Commercial insurance covered \$400  
20 million per occurrence after a deductible of \$7.5 million.

21 **Q. When did the change from captive insurance coverage to self insurance take**  
22 **effect?**

23 A. The Company's captive insurance coverage expired March 21, 2011. Coverage

1 currently provided by commercial carriers will continue, and the related  
2 premiums are included in this case at actual levels. The Test Period in this case  
3 includes captive insurance coverage until March, 21, 2011, and self insurance  
4 accruals thereafter.

5 **Q. What will be the new level of coverage for storm or casualty events?**

6 A. The initial deductible for each storm or casualty O&M event damaging  
7 distribution property will be raised from the current level of \$25,000 to \$250,000.  
8 The deductible for O&M transmission and non-T&D property damages will be \$1  
9 million per event. O&M related damages for all costs up to these deductible limits  
10 will be charged to the proper functional O&M FERC account. Amounts  
11 exceeding these deductible limits will be charged to the accumulated insurance  
12 reserve. There will be no reserve amounts related to capital projects.

13 **Q. Please describe the Test Period treatment of third-party liability insurance.**

14 A. As shown on page 4.11.2 of Exhibit No. 2, captive insurance premiums and  
15 coverage are assumed only through March 21, 2011. For the Test Period self-  
16 insurance accruals replace the captive premiums after March 21. The level of the  
17 self-insurance accrual is set based on the annual average of liability claims related  
18 to O&M payments by MEHC captive insurance from January 2008 through  
19 December 2010. Idaho's allocated portion of the Test Period amount is based on  
20 the System Overhead ("SO") factor. The injuries and damages expense the  
21 Company incurs in addition to the amount previously covered by the captive are  
22 included based on a three-year average of the net expense accrued, consistent with  
23 the Company's 2010 General Rate Case.

1 **Q. Please describe the treatment of property insurance in the Test Period.**

2 A. As shown on page 4.11.3 of Exhibit No. 2, captive insurance premiums and  
3 coverage for T&D and non-T&D property are assumed to be in place only  
4 through March 21, 2011. For the Test Period, self insurance accruals after March  
5 21 are set based on the annual average of actual damages from April 2007 through  
6 December 2010. Damages are included in the average calculation only to the  
7 extent they exceed the revised deductibles by category. The allocation of accruals  
8 and actual storm or casualty costs will be consistent with the allocation of similar  
9 types of electric plant in service (i.e. distribution is situs assigned and  
10 transmission and non-T&D are allocated on the SG factor) in place at the time.

11 Due to the increase in deductible limits, expenses for property damages  
12 that are currently classified as insurance expense are effectively being transferred  
13 to O&M. Page 4.11.4 of Exhibit No. 2 shows that the increase in deductible limits  
14 reduces the amount of storm or casualty events that would be covered by the  
15 insurance reserve. Costs not covered by the insurance reserve would need to be  
16 covered by the Company's ongoing O&M. The Company has included the effect  
17 of this transfer as an O&M expense of \$562,000 in the Test Period in order to set  
18 rates at a level that will adequately cover expected storm and casualty damage  
19 below the new deductible threshold.

20 **Q. Please describe the accounting entries that will be booked once self insurance**  
21 **coverage begins.**

22 A. Each month, debits will be made to FERC account 924 – Property Insurance, with  
23 the corresponding credits booked to insurance reserves in FERC account 254 on a

1 state-specific basis. Separate internal accounting orders will be used for the  
2 reserve balances to track the state-specific amounts associated with the liability  
3 and property balances. When the Company experiences an insurance event, the  
4 reserve balance will be debited to pay for the damages incurred allocated to Idaho  
5 using then-current allocation factors. If the Company experiences events in excess  
6 of the accumulated reserve balance, or anticipated reserve balance through the  
7 remaining portion of each calendar year, the Company will accumulate these  
8 amounts as a regulatory asset until such time as the allowed annual accrual  
9 amount covers such losses or specific recovery for an event is requested and  
10 approved.

11 **Q. What is the impact of the Company’s proposal on Idaho customers in this**  
12 **case?**

13 A. Overall, the Company’s proposal results in a slight decrease in costs allocated to  
14 Idaho compared to the actual costs in the year ended December 2010. Page 4.11  
15 of Exhibit No. 2 shows the Idaho-allocated impact of the adjustments for both  
16 liability and property insurance. The net Idaho-allocated expense decreases  
17 approximately \$15,000.

18 **Q. Please describe the Company’s requested change to the depreciation**  
19 **associated with the Klamath facilities.**

20 A. Consistent with the Klamath Hydroelectric Settlement Agreement (“KHSA”),  
21 depreciation of all Klamath Project facilities (existing assets, relicensing and  
22 settlement process costs, and future capital additions) is set at a level that will  
23 fully depreciate the assets by December 31, 2019. Depreciation associated with

1 the existing Klamath Project facilities is accelerated from current rates effective  
2 January 1, 2011. The Company will monitor the depreciation expense booked in  
3 the future to ensure assets reach a zero net book value by December 31, 2019. The  
4 impact of the change in depreciation rates is shown on page 8.12 of Exhibit 2; on  
5 an Idaho-allocated basis, depreciation expense in this case is increased by  
6 \$262,161.

7 **Q. Please describe how the Company proposes to monitor the depreciation rates**  
8 **to ensure that the Klamath assets reach a net book value of zero by**  
9 **December 31, 2019.**

10 A. The Company proposes to provide the Commission an annual report regarding the  
11 composite depreciation rates related to the Klamath facilities for the previous  
12 calendar year and the rates currently in effect at year-end. This report could be  
13 provided as part of the Company's annual results of operations or as a separate  
14 filing. In this case, the Company is requesting the Commission approve the  
15 terminal date for depreciation of the assets, which will result in rates varying  
16 slightly over the remaining life as a result of potential retirements and additions  
17 required to keep the facility operational. Once approved, additional action by the  
18 Commission would not be required. The Commission can continue to monitor the  
19 rates and related depreciation expense through the Company's annual reports. If  
20 the terminal date changes in the future, the Company would include the impact in  
21 a general rate case in a similar manner as presented in the current case and seek  
22 Commission approval of that change.

1 **Idaho Results of Operations**

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

4 A. Revenue requirement preparation began with historical accounting information; in  
5 this case the Company used the 12-months ended December 31, 2010. The  
6 revenue requirement components in that historical period were analyzed to  
7 determine if an adjustment was warranted to reflect normal operating conditions.  
8 The historical information was also adjusted to recognize known and measurable  
9 events, and to include previous Commission-ordered adjustments.

10 As stated earlier, historical rate base is calculated using end-of-period  
11 balances as of December 31, 2010. Major capital additions planned to go into  
12 service by December 31, 2011, are added based on the full cost expected to be  
13 placed into service. In order to synchronize other components of the revenue  
14 requirement, costs and benefits related to these major plant additions are included  
15 in revenue requirement on an annualized level regardless of the date the resource  
16 will go into service.

17 **Q. Please describe Exhibit No. 2.**

18 A. Exhibit No. 2 is Rocky Mountain Power's Idaho results of operations report (the  
19 "Report"). The Report provides totals for revenue, expenses, net power costs,  
20 depreciation, taxes, rate base and loads in the Test Period. The Report presents  
21 operating results for the period in terms of both return on rate base and ROE.

22 **Q. Please describe how Exhibit No. 2 is organized.**

23 A. The Report is organized into sections marked with tabs as follows:

- 1                   • Tab 1 Summary contains a summary of normalized Idaho-allocated  
2                   results of operations.
- 3                   • Tab 2 Results of Operations details the Company’s overall revenue  
4                   requirement, showing unadjusted costs for the year ended December  
5                   2010 and fully normalized results of operations for the Test Period by  
6                   FERC account.
- 7                   • Tabs 3 through 8 provide supporting documentation for the  
8                   normalizing adjustments required to reflect on-going costs of the  
9                   Company. Each of these sections begins with a numerical summary  
10                  that identifies each adjustment made to the 2010 actual results and the  
11                  adjustment’s impact on the case. Each column has a numerical  
12                  reference to a corresponding page in Exhibit No. 2, which contains a  
13                  lead sheet showing the adjusted FERC account(s), allocation factor,  
14                  dollar amount and a brief description of the adjustment. The specific  
15                  adjustments included in each of these tab sections are described in  
16                  more detail below.
- 17                  • Tab 9 shows the impacts of several items addressed by the  
18                  Commission in the 2010 General Rate Case that are not implemented  
19                  in the Company’s request. More discussion on Tab 9 was provided  
20                  earlier in my testimony.
- 21                  • Tab 10 contains the calculation of the 2010 Protocol allocation factors.
- 22                  • Tab 11 is Tab 2 restated based on the Revised Protocol allocation  
23                  method.

- 1                   • Tab 12 is Tab 2 restated based on the Rolled-In allocation method.
- 2                   • Tabs B1 through B20 provide backup for the actual results included in
- 3                   tab 2.
- 4                   • Tab C1 provides the Company’s 2007 lead lag Study.

5   **Tab 3 – Revenue Adjustments**

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

7   A.   **Temperature Normalization (page 3.1)** – This adjustment recalculates Idaho  
8       revenue based on temperature normalized historical load assuming average  
9       temperature patterns.

10       **Revenue Normalization (page 3.2)** – This adjustment normalizes base year  
11       revenue by removing items that should not be included to determine retail rates,  
12       such as credits from the Bonneville Power Administration (“BPA”) for the  
13       Residential Exchange Program, amortization of the Sacramento Municipal Utility  
14       District (“SMUD”) liability and collections related to the ECAM. The expense  
15       side of the BPA credit is removed in adjustment 5.2.

16       **Effective Price Change (page 3.3)** – This adjustment reflects the \$8.1 million  
17       revenue increase which became effective on December 28, 2010, as a result of the  
18       2010 General Rate Case. This adjustment also normalizes the pro forma effects  
19       for the \$6.46 million special contract price change effective January 1, 2011, also  
20       determined in the 2010 General Rate Case.

21       **SO2 Emission Allowances (page 3.4)** – This adjustment removes revenue from  
22       the sale of sulfur dioxide (“SO2”) emission allowances occurring during the base  
23       period and replaces it with the corresponding grandfathered amortization through

1 the Test Period. Prior to the 2010 General Rate Case, these sales were amortized  
2 over a 15 year period, but in the 2010 General Rate Case the Company agreed to  
3 shorten the amortization of the remaining balances to five years. Thus,  
4 unamortized balances of sales prior to June 30, 2009, are amortized over five  
5 years to reflect this new methodology. Revenue from the sale of SO2 emission  
6 allowances after June 30, 2009, is returned to customers through the ECAM per  
7 Case No. PAC-E-08-08.

8 **Renewable Energy Credit (“REC”) Revenue (page 3.5)** – Currently,  
9 California, Washington and Oregon have implemented renewable portfolio  
10 standards. Consequently, the Company does not sell these states’ share of eligible  
11 RECs. Instead, the Company uses the renewable output to comply with current  
12 year or future year renewable portfolio requirements. This adjustment reflects the  
13 amount of REC revenues the Company expects during the Test Period and  
14 allocates the REC revenue among states to account for compliance in California,  
15 Washington and Oregon. Any differences between the projected REC revenues in  
16 this adjustment and actual REC revenues will be accounted for in the Company's  
17 ECAM filings as ordered by the Idaho Commission in Order No. 32196.

18 **Wheeling Revenue (page 3.6)** – During 2010 there were various transactions  
19 involving wheeling revenue that the Company does not expect to occur in the Test  
20 Period. These transactions relate to various prior period adjustments and contract  
21 terminations. This adjustment also includes pro forma wheeling revenue for the  
22 Test Period.

1 **Tab 4 – O&M Adjustments**

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

3 A. **Miscellaneous General Expense (page 4.1)** – This adjustment removes certain  
4 miscellaneous expenses that should have been charged to non-regulated accounts.  
5 **Wage and Employee Benefits (pages 4.2 and 4.3)** – This adjustment is used to  
6 compute labor-related costs for the Test Period. Labor-related costs are calculated  
7 by adjusting salaries, incentives, benefits, and costs associated with FAS 87  
8 (pension), FAS 106 (post retirement benefits) and FAS 112 (post employment  
9 benefits) for changes expected beyond the actual costs experienced in the year  
10 ended December 2010. Page 4.3.4 provides a numerical summary starting with  
11 actual labor costs in 2010 and summarizing the adjustments made to reflect the  
12 Test Period level of expense.

13 The first step to adjust labor is to annualize salary increases that occurred  
14 during 2010. This was done by identifying actual wages by labor group by month  
15 along with the date each labor group received wage increases. The next step is to  
16 apply pro forma wage increases through the end of the Test Period to the  
17 annualized 2010 salaries. Union contract agreements are used to escalate union  
18 wages, while increases for non-union and exempt employees are based on actual  
19 increases. In other words, wages in the Test Period are actual costs adjusted only  
20 for contractual changes or known increases that have already occurred. The only  
21 exception to this is Locals IBEW 125 and IBEW 659 where 2011 planning targets  
22 were used as union negotiations are currently ongoing.

23 Incentive compensation, used by the Company to deliver market

1 competitive pay, is included based on 2011 pro forma wages multiplied by a three  
2 year average of the actual payment rate. Payroll taxes were updated to capture any  
3 associated impacts of the changes to labor costs. Other employee benefit costs  
4 were itemized starting with amounts booked during the year ended December  
5 2010 and adjusted to the planned expense for the Test Period. This adjustment is  
6 further supported by the testimony of Company witness Mr. Wilson.

7 **Class 1 DSM Program Costs (page 4.4)** – In accordance with Order No. 32196  
8 in the 2010 General Rate Case, costs of the Idaho Irrigation Load Control  
9 Program are allocated system-wide, including both customer incentives and  
10 program administration costs. In addition, this adjustment allocates the costs of  
11 Class 1 DSM programs in other states to all jurisdictions. The Idaho Irrigation  
12 Load Control Program incentive payments are already allocated as a system cost  
13 in the Company's unadjusted results, but the other costs referenced are added to  
14 results in this adjustment. The jurisdictional loads used for allocation factors  
15 reflect system treatment for these programs, consistent with the Commission  
16 Order and this adjustment. In other words, no reductions in load resulting from  
17 program operations in 2010 are reflected for purposes of inter-jurisdictional  
18 allocations.

19 **Remove Non-Recurring Entries (page 4.5)** – This adjustment removes various  
20 accounting entries made during 2010 that were non-recurring in nature or relate to  
21 a prior period.

22 **Pension Curtailment (page 4.6)** – During the base period the Company made an  
23 entry to reflect the actuarial effects of the UMWA 127 pension curtailment. Since

1 Idaho uses a cash basis for pension expense, this adjustment removes this entry.

2 **DSM Revenue and Expense Removal (page 4.7)** – This adjustment removes  
3 Idaho DSM revenue and expenses which are accounted for through the customer  
4 efficiency services rate adjustment (Schedule 191).

5 **Wyoming Inverted Rates Advertising (page 4.8)** – This adjustment removes the  
6 credit booked to set up a regulatory asset to defer advertising costs that were  
7 ordered by the Wyoming Public Service Commission and are being recovered  
8 from Wyoming customers.

9 **MEHC Transition Cost Amortization (page 4.9)** – The Company eliminated  
10 many positions in its labor force as a result of the MEHC transaction. These  
11 savings were made possible by the payment of change-in-control severance,  
12 which is currently being amortized over a three year period as authorized in Case  
13 Nos. PAC-E-06-11 and PAC-E-07-05. Because the amortization ended December  
14 31, 2010, it is being removed from unadjusted results. This adjustment also  
15 removes from unadjusted results the credit booked when the Oregon and  
16 California transition plan regulatory assets were established.

17 **MEHC Cross Charge (page 4.10)** - The Company has included the actual  
18 MEHC cross charge expense from 2010. This adjustment removes SERP expense  
19 from the cross charge consistent with Order No. 32196 in the 2010 General Rate  
20 Case.

21 **Insurance Expense (page 4.11)** – This adjustment reflects changes to the  
22 Company’s insurance expense as described above in my testimony under the  
23 Accounting Changes section.

1       **Generation Overhaul Expense (page 4.12)** – This adjustment normalizes  
2       generation overhaul costs by averaging actual overhaul expenses over four years.  
3       For new generating units, which include Lake Side and Chehalis, the four-year  
4       average is comprised of the actual overhaul expense to the extent it is available  
5       and projected expense to complete the first four full years these plants are  
6       operational. The adjustment is calculated by subtracting the actual overhaul costs  
7       from the four year historical average.

8       **Incremental O&M (page 4.13)** – This adjustment annualizes incremental O&M  
9       related to new generation plant in service, improvements to plants, or  
10       transmission projects that were placed into service during the 12-months ended  
11       December 2010, and includes projected O&M expense for projects placed into  
12       service during the 12-months ending December 2011. The adjustment also  
13       addresses two known changes in O&M at existing facilities. First, on December  
14       29, 2010, the Company sold to Black Hills, Co. an undivided joint ownership  
15       interest in certain transmission facilities, causing a reduction in ongoing O&M  
16       expense. Second, as of December 2010, with the depletion of the McKinley Mine,  
17       the Cholla 4 plant will be using coal from a different source which requires  
18       additional scrubbing and therefore requires higher volumes of scrubbing agents.

19       **Memberships and Subscriptions (page 4.14)** – This adjustment removes  
20       expense in excess of Commission policy as stated in Order No. 29505. National  
21       and regional trade organizations are recognized at 75 percent of above the line  
22       costs and dues for membership in Western Electric Coordinating Council  
23       (“WECC”) and Northern Tier Transmission Group are included at 100 percent.

1 Other membership dues are removed.

2 **Intervenor Funding (page 4.15)** – This adjustment accounts for intervenor  
3 funding awarded to the Community Action Partnership of Idaho (“CAPAI”), the  
4 Idaho Irrigation Pumpers Association (“IIPA”) and the Idaho Conservation  
5 League (“ICL”), as ordered in Case No's. PAC-E-07-05, PAC-E-08-07, PAC-E-  
6 10-07 and PAC-E-08-08. Amortization expense is adjusted to reflect the expected  
7 amount through the year ending December 2011, and rate base is adjusted to  
8 reflect the December 2011 remaining balance.

9 **Idaho Pension Expense - Cash Basis (page 4.16)** – This adjustment replaces the  
10 actuarially determined pension expense for the Test Period with the three-year  
11 average of cash contributions, consistent with the Commission’s Order No.  
12 32196.

13 **Uncollectible Expense (page 4.17)** – As discussed earlier in my testimony,  
14 uncollectible expense is adjusted to a three-year historical average (2008-2010)  
15 per Commission Order No. 32196.

16 **Outside Services (page 4.18)** – As discussed above, outside services expense is  
17 adjusted to a three-year historical average (2008-2010) per Commission Order  
18 No. 32196.

19 **Tab 5 – Net Power Cost Adjustments**

20 **Q. Please describe the adjustments included in Tab 5.**

21 A. **Net Power Cost Study (page 5.1)** – The net power cost adjustment presents  
22 normalized Test Period generation, fuel, purchased power, wheeling expense and  
23 sales for resale based on the Company’s GRID model. It also normalizes hydro,

1 weather conditions and plant availability as described in Mr. Duvall’s testimony.  
2 **James River Royalty Offset and Little Mountain Steam Sales (page 5.2)** – On  
3 January 13, 1993, the Company executed a contract with James River Paper  
4 Company with respect to the Camas mill, later acquired by Georgia Pacific.  
5 Under the agreement, the Company built a steam turbine and is recovering the  
6 capital investment over the twenty-year operational term of the agreement as an  
7 offset to royalties paid to James River based on contract provisions. The contract  
8 costs of energy for the Camas unit are included in the Company’s net power costs  
9 as purchased power expense, but GRID does not include an offsetting revenue  
10 credit for the capital and maintenance cost recovery. This adjustment adds the  
11 royalty offset to account 456, other electric revenue, for the Test Period.

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

18 **Electric Lake Settlement (page 5.3)** – Canyon Fuel Company (“CFC”) owns the  
19 Skyline mine located near Electric Lake. Electric Lake is a reservoir owned by the  
20 Company that provides water storage for the Huntington generating plant. The  
21 two companies disputed a claim made by PacifiCorp that CFC’s mining  
22 operations caused the lake to leak water into the Skyline mine, making it  
23 unavailable for use by the Huntington generating plant. The Company has

1 incurred capital costs and O&M costs to pump water from the breach back into  
2 Electric Lake. The two companies negotiated a settlement of the claims made by  
3 the Company. The settlement includes reimbursement to the Company for O&M  
4 and capital associated with the pumping. The value of the settlement was  
5 amortized over three years, which was completed January 2011. This adjustment  
6 removes the Test Period amortization and rate base balances from results.

7 **BPA Residential Exchange (page 5.4)** – The Company receives a monthly  
8 purchase power credit from Bonneville Power Administration (“BPA”). This  
9 credit is treated as a 100% pass-through to eligible customers. As a result of the  
10 Ninth Circuit Court of Appeals decision, BPA offsets this credit against a look  
11 back payment to the public utilities. To date this look back has been larger than  
12 the BPA credit in Idaho. This adjustment reverses the related entries to purchase  
13 power expense. The revenue normalizing adjustment on page 3.2 removes the  
14 offsetting entries to retail revenue.

15 **Tab 6 – Depreciation and Amortization Expense Adjustments**

16 **Q. Please describe the adjustments included in Tab 6.**

17 A. **Depreciation and Amortization Expense (page 6.1)** – This adjustment  
18 normalizes the Test Period results for depreciation and amortization expense  
19 associated with the major plant additions to rate base in adjustment 8.6.

20 **Depreciation and Amortization Reserve (page 6.2)** – This adjusts the  
21 depreciation and amortization reserve to include the depreciation and amortization  
22 expense from adjustment 6.1 associated with the major plant additions in  
23 adjustment 8.6.

1        **Hydro Decommissioning (page 6.3)** – Based on the Company's latest  
2        depreciation study approved in Case No. PAC-E-07-14, an annual accrual of  
3        \$19.4 million is required for the decommissioning of various hydro facilities. This  
4        adjusts the decommissioning reserve balance to the end of the Test Period level.

5        **Tab 7 – Tax Adjustments**

6        **Q.     Please describe the adjustments included in Tab 7.**

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

11       **Property Tax Expense (page 7.2)** – This adjustment normalizes property tax  
12       expense to include the taxes associated with capital additions. Please refer to  
13       Confidential Exhibit No. 3 for details supporting the Test Period expense.

14       **Renewable Energy Tax Credit (page 7.3)** – The Company is entitled to  
15       recognize certain production tax credits as a result of generation from qualifying  
16       renewable generating facilities. The federal tax credit is based on the generation  
17       of the plants and the credit can be taken for 10 years on qualifying property.  
18       Under the calculation required by Internal Revenue Service Code Sec. 45(b)(2),  
19       the Test Period renewable electricity production credit is 2.2 cents per kilowatt  
20       hour of electricity produced from wind facilities. The Utah state tax credit is  
21       based on the generation of the Blundell bottoming cycle; the credit can be taken  
22       for four years. In addition to the Utah state tax credit, the Company is able to  
23       recognize the Oregon Business Energy Tax Credit, which is based on investment

1 in specific assets and is taken over a five year period.

2 **Idaho State Investment Tax Credit (page 7.4)** – The Idaho state investment tax  
3 credit (“ITC”) is based on plant placed in service, and the credit is usually utilized  
4 in a subsequent period depending on the availability of Idaho state taxable  
5 income. Since PacifiCorp is a 46(f)(1) Company, this adjusts results to reflect the  
6 ITC unamortized balance as a rate base reduction.

7 **AFUDC Equity (page 7.5)** – This adjustment aligns the AFUDC – Equity in  
8 results with the tax Schedule M’s associated with regulatory income.

9 **Post Retirement Benefits Tax Deferral (page 7.6)** – As approved in the 2010  
10 General Rate Case, this adjustment recognizes the amortization of the post  
11 retirement benefits tax deferral regulatory asset for the 12-months ending  
12 December 2011.

13 **Accumulated Deferred Income Tax Balance Adjustment (page 7.7)** – This pro  
14 forma adjustment reflects the known and measurable change to the accumulated  
15 deferred income tax balances for guidance received from the Internal Revenue  
16 Service (Rev. Proc. 2011-26) on March 29, 2011, which affected the Company's  
17 estimate of bonus depreciation for assets placed in service during 2010.

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

19 A. Current state and federal income tax expenses were calculated by applying the  
20 applicable tax rates to the taxable income calculated in the Report. State income  
21 tax expense was calculated using the blended state statutory rate applied to the  
22 jurisdictional pre-tax income. The treatment of state taxes is also discussed under  
23 the Inter-Jurisdictional Allocation section of my testimony. Federal income tax

1 expense is calculated using the same methodology that the Company uses in  
2 preparing its filed income tax returns. The detail supporting this calculation is  
3 contained on pages 2.18 through 2.20 of Exhibit No. 2.

4 **Tab 8 – Rate Base Adjustments**

5 **Q. Please describe the adjustments included in Tab 8.**

6 A. **Update Cash Working Capital (page 8.1)** – This adjustment supports the  
7 calculation of cash working capital included in rate base for the Test Period. Total  
8 cash working capital is calculated by multiplying the jurisdictional net lag days by  
9 the average daily cost of service. Net lag days in this case are based on a lead lag  
10 study prepared by the Company using calendar year 2007 information. Based on  
11 the results of the 2007 lead lag study, included in Tab C1 of Exhibit No. 2, the  
12 Company experiences 4.72 net lag days in Idaho requiring a cash working capital  
13 balance of \$1.8 million to be included in rate base.

14 The cash working capital calculation is consistent with the treatment  
15 included in the last two general rate cases. In the 2010 General Rate Case, the  
16 Commission accepted the Company’s 2007 lead lag study with the directive that  
17 in the next rate case the Company demonstrate that a lead lag study appropriately  
18 considers the source of the funds. The Company believes the lead lag study  
19 methodology to be the best measurement of the Company’s required working  
20 capital funds and appropriately considers the source of the funds. There are three  
21 viable sources to provide a utility’s working capital funds: debt, equity and  
22 payment terms (or the difference between when the Company receives payment  
23 from a customer and pays for the cost of providing service). The first two sources

1 of these funds are supplied by investors. The third source may be provided by  
2 investors or customers, and a lead lag study is the best method of determining  
3 which group is responsible. The Company's 2007 lead lag study shows a net lag,  
4 meaning that investors must infuse cash into the business for day-to-day  
5 operations. Based on the Company's latest FERC Form 1 filing, the Company's  
6 current assets exceed the current liabilities, suggesting that the Company requires  
7 more working capital than is supplied by customers. This supports the findings of  
8 the lead lag study and demonstrates that the lead lag study offers reasonable  
9 analysis on the source of funds. The Company believes that actual working capital  
10 requirements of a utility are best measured by examining the dynamic cash flows  
11 as done in a lead lag study instead of a looking at a snapshot of account balances.  
12 Therefore, the Company continues to advocate for the use of its 2007 lead lag  
13 study as the most accurate tool for determining the level of working capital  
14 required for ongoing operations to serve customers.

15 **Trapper Mine Rate Base (page 8.2)** – The Company owns a 21.4 percent share  
16 of the Trapper Mine, which provides coal to the Craig generating plant. This  
17 investment is accounted for on the Company's books in FERC account 123.1,  
18 investment in subsidiary company, which is not included as a regulatory rate base  
19 account. The normalized coal cost from Trapper Mine in net power costs includes  
20 operation and maintenance costs but does not include a return on investment. This  
21 adjustment adds the Company's portion of the Trapper Mine net plant investment  
22 to rate base in order for the Company to earn a return on its investment. This  
23 adjustment also walks forward the reclamation liability through December 2011.

1       **Jim Bridger Mine Rate Base (page 8.3)** – The Company owns a two-thirds  
2 interest in the Bridger Coal Company, which supplies coal to the Jim Bridger  
3 generating plant. The Company’s investment in Bridger Coal Company is  
4 recorded on the books of Pacific Minerals, Inc. Because of this ownership  
5 arrangement, the coal mine investment is not included in electric plant in service.  
6 The normalized coal costs for Bridger Coal Company in net power costs include  
7 the operation and maintenance costs of the mine but provide no return on  
8 investment. This adjustment is necessary to properly reflect the Bridger Coal  
9 Company investment in rate base in order for the Company to earn a return on its  
10 investment.

11       **Environmental Settlement (PERCO) (page 8.4)** – In 1996, the Company  
12 received an insurance settlement of \$33 million for environmental clean-up  
13 projects. These funds were transferred to a subsidiary called PacifiCorp  
14 Environmental Remediation Company (“PERCO”). This fund balance is  
15 amortized or reduced as PERCO expends dollars on clean-up costs. PERCO  
16 received an additional \$5 million of insurance proceeds plus associated liabilities  
17 from Rocky Mountain Power in 1998. This adjustment reduces rate base for the  
18 unspent insurance proceeds through the end of the Test Period. The Company  
19 expects the funds to be exhausted during 2011.

20       **Customer Advances for Construction (page 8.5)** – Refundable customer  
21 advances for construction are recorded to FERC account 252. The December  
22 2010 balances do not reflect the proper allocation because amounts were recorded  
23 to a corporate cost center location rather than state-specific locations in the

1 Company's accounting system. This adjustment corrects the allocation of  
2 customer advances.

3 **Pro Forma Major Plant Additions (page 8.6)** – To reasonably represent the cost  
4 of system infrastructure required to serve our customers, the Company has  
5 identified capital projects that will be completed by the end of the Test Period.  
6 Company business units identified capital projects with expenditures over \$5  
7 million that will be used and useful by December 31, 2011. These additions are  
8 summarized by functional category, indicating the in-service date and amount by  
9 project. The associated depreciation expense and accumulated reserve impacts are  
10 accounted for in adjustment 6.1 and 6.2. The associated tax impacts are included  
11 on page 8.6.1.

12 **Miscellaneous Rate Base (page 8.7)** – In this adjustment fuel stock is increased  
13 due to the cost of coal and the number of tons stored at each site. Also, prepaid  
14 overhaul balances in FERC account 186 for the Lake Side, Chehalis, and Currant  
15 Creek plants are adjusted forward to reflect future payments and transfers of  
16 capital to electric plant in service expected during the Test Period.

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

23 This adjustment reflects the ratemaking treatment approved by the

1 Commission in Case No. PAC-E-07-04. During 2007, the net book value  
2 (including an offset for insurance proceeds) of the assets to be retired was  
3 transferred to the unrecovered plant regulatory asset, which was fully amortized  
4 on December 31, 2010. In addition, decommissioning costs are deferred as they  
5 are spent and amortized over 10 years, beginning in the subsequent year. The  
6 decommissioning project was substantially completed during 2010.

7 **Goose Creek Transmission (page 8.9)** – On April 1, 2008, the Company sold its  
8 undivided interest in 13.85 miles of transmission line, running from the  
9 Company's Goose Creek switching station and extending north to the Decker 230  
10 kV substation near Decker, Montana. The assets sold included structures,  
11 miscellaneous support equipment, easements, and rights-of-way associated with  
12 the transmission line. The sale of the transmission line resulted in the Goose  
13 Creek switching station no longer being needed or useful to the Company, and the  
14 Company plans to remove all above ground facilities at the switching station.  
15 Consistent with Commission Order No. 30904, in September 2009 the Company  
16 wrote off the gain associated with the sale. This adjustment removes the rate base  
17 and depreciation expense included in December 2010 unadjusted results.

18 **FERC 105 (PHFU) (page 8.10)** – This adjustment removes all plant held for  
19 future use (“PHFU”) assets from FERC account 105. The Company is making  
20 this adjustment in compliance with Title 16 of Public Utility Regulation, chapter  
21 5, "Powers and Duties of Public Utilities Commission" section 61-502A.

22 **Trojan Unrecovered Plant (page 8.11)** – The regulatory assets associated with  
23 Trojan unrecovered plant and decommissioning will be fully amortized as of

1 January 2011. This adjustment removes the amortization expense and rate base  
2 balances from the Test Period.

3 **Klamath Hydroelectric Settlement Agreement (“KHSa”) (page 8.12)** – This  
4 adjustment accounts for the impact of the KHSa including: amortization of the  
5 Klamath relicensing and settlement process costs, accelerated depreciation  
6 associated with the existing Klamath facilities (starting in January 1, 2011, and  
7 finishing by December 31, 2019) and incurred operation and maintenance  
8 expenses. Under the 2010 Protocol, a surcharge to cover the cost of facilities  
9 removal is initially allocated to Idaho, but is re-assigned to Oregon and California  
10 through the 2010 Protocol Klamath surcharge adjustment. The accelerated  
11 depreciation associated with the existing Klamath facilities was discussed in detail  
12 above.

13 **Tab 9 – PAC-E-10-07 Items**

14 **Q. Please describe the information contained behind Tab 9.**

15 A. As described earlier in my testimony, Tab 9 contains the impacts of several items  
16 addressed in Commission Order No. 32196 in the 2010 General Rate Case.

17 **Tab 10 – Allocation Factors**

18 **Q. Please describe the information contained behind Tab 10 Allocation Factors.**

19 A. Tab 10 Allocation Factors summarizes the derivation of the jurisdictional  
20 allocation factors using the 2010 Protocol allocation methodology. Factors in this  
21 case are based on the actual loads through December 2010 and unadjusted  
22 account balances.

1 **Tab 11 – Revised Protocol**

2 **Q. Please describe the information contained behind Tab 11 Revised Protocol.**

3 A. Tab 11 is Tab 2 restated with the Idaho allocation based on the Revised Protocol  
4 allocation method. The Company agreed to provide this information in its reply  
5 comments in the pending 2010 Protocol Case.

6 **Tab 12 – Rolled-In**

7 **Q. Please describe the information contained behind Tab 12 Rolled In.**

8 A. Tab 12 is Tab 2 restated with the Idaho allocation based on the Rolled-In  
9 allocation method. The Company agreed to provide this information in its reply  
10 comments in the pending 2010 Protocol Case.

11 **Tab C1 – 2007 Lead Lag Study**

12 **Q. Please describe the information contained behind Tab C1 2007 Lead Lag**  
13 **Study.**

14 A. Tab C1 contains the Company’s 2007 lead lag study as discussed earlier in my  
15 testimony under the Tab 8 - Rate Base section.

16 **Load Change Adjustment Rate**

17 **Q. Has the Company updated the calculation of the LCAR that is applied to the**  
18 **calculation of net power costs to be recovered through the ECAM?**

19 A. Yes. Exhibit No. 4 provides the detailed calculation based on the revenue  
20 requirement numbers from Exhibit No. 2. Using the revenue requirement in the  
21 Company’s filing results in an increase in the LCAR from \$5.47 per MWh to  
22 \$6.17 per MWh. To calculate the LCAR I have incorporated the applicable  
23 elements from this case, including production-related return on investment and

1 non-NPC expenses. My calculation does not include demand related charges as  
2 approved by the Commission in Case No. GNR-E-10-03 Order No. 32206. The  
3 LCAR itself does not affect revenue requirement in this case, but is applied to the  
4 calculation of net power costs to be deferred and recovered through the ECAM  
5 and is to be updated each time base net power costs are updated in a general rate  
6 case. The Company will also provide an updated calculation of this rate based on  
7 the Commission-approved outcome of this case.

8 **Conclusion**

9 **Q. Do you believe the proposed revenue increase supported by your calculation**  
10 **of revenue requirement is in the public interest?**

11 A. Yes. The Company's proposed revenue increase is in the public interest because it  
12 balances the needs of customers and the Company by setting rates at a level  
13 commensurate with the reasonable and prudent cost of providing safe and reliable  
14 service when those rates will be in effect.

15 **Q. Does this conclude your direct testimony?**

16 A. Yes.