

**BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING**

In the Matter of the Application of Rocky Mountain Power, for Approval of a General Rate Increase of Approximately \$36.1 Million per Year for Retail Electric Utility Service in Wyoming, and for Approval of a New Renewable Resource Mechanism and Marginal Cost Pricing Tariff )

Docket No. 20000-277-ER-07  
Record No. 11249

**PRE-FILED DIRECT TESTIMONY OF**

**Denise Kay Parrish**

**On Behalf of the Office of Consumer Advocate**

**PUBLIC (NON-CONFIDENTIAL) VERSION**

Testimony Filed: January 7, 2008

Hearing Begins: March 3, 2008

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is Denise Kay Parrish and my business address is 2515 Warren Avenue, Suite  
3 304, Cheyenne, Wyoming 82002.

4  
5 **Q. WHAT IS YOUR OCCUPATION?**

6 A. I am currently the Deputy Administrator of the Wyoming Office of Consumer Advocate  
7 (OCA). In this position, I review and provide input into the recommendations made by  
8 the OCA. I review utility applications filed with the Wyoming Public Service  
9 Commission (Commission) and provide advice to the Administrator regarding the  
10 involvement the OCA should have, if any, in the various cases. I review applications,  
11 perform analyses and provide recommendations to the Commission relative to various  
12 utility matters, including revenue requirements, tariff language, competitive issues, rules  
13 and regulations, and other items. I write and issue press releases, perform special studies,  
14 as well as provide information and research to customers, the legislature, the OCA  
15 Administrator, and others. I do other assignments and tasks, as needed and as assigned  
16 by the OCA Administrator.

17  
18 **Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

19 A. In 1976, I graduated from Michigan State University with a Bachelor's degree in  
20 Accounting. I have spent thirty years as a regulator of public utilities, having been on the  
21 staff of four state utility regulatory commissions and two consumer advocate entities.  
22 More than fifteen of these years have been spent at the Wyoming Public Service  
23 Commission. I have taken classes related to various aspects of public utility regulation,  
24 including income taxes, regulatory accounting, capital recovery, cost-of-service, rate  
25 design, revenue requirements, separations and allocations, and other specialized topics. I  
26 have taught classes on issues of accounting standards, general ratemaking principles,  
27 affiliate transactions, regulatory accounting, financial reporting, and other specialized  
28 topics to regulatory professionals.

29  
30 Since 2002, I have been an instructor at the Michigan State University Institute of Public  
31 Utilities (CAMP NARUC). I have also worked with the Nigerian Communications

1 Commission on regulatory accounting and reporting matters and have done work for the  
2 International Telecommunications Union as a seminar leader. Furthermore, I have  
3 participated as a presenter at several meetings of the Tariff and Pricing Committee of the  
4 Energy Regulators Regional Association (ERRA). Finally, I was a presenter at, and  
5 participant in a workshop sponsored by the Energy Group of the Institute of International  
6 Education (IIE) regarding the development of an Electricity Distribution Indicator  
7 Toolkit.

8  
9 I am the past chair and a current member of the National Association of Regulatory  
10 Utility Commissioners' Staff Subcommittee on Accounting and Finance. I am a member  
11 of the NARUC Staff Subcommittee on International Relations. I am listed in the current  
12 edition of Who's Who of American Women. I am currently a member of the National  
13 Association of State Utility Consumer Advocates' (NASUCA) Tax and Accounting  
14 Committee. Finally, I am a member of the staff of the Federal-State Joint Board on  
15 Universal Service.

16  
17 **Q. DO YOU HAVE EXPERIENCE AS AN EXPERT WITNESS?**

18 A. Yes. I have testified more than one hundred twenty-five times as an expert witness. I  
19 have testified before the Michigan Public Service Commission, the Colorado Public  
20 Utilities Commission, the Colorado District Court, the Arizona Corporations  
21 Commission, the Wyoming Public Service Commission, the Wyoming Legislature Joint  
22 Corporations Committee, the Federal Energy Regulatory Commission, and the Federal-  
23 State Joint Board on Universal Service. I have testified in telecommunications, water,  
24 wastewater, electric, and natural gas cases. The subjects upon which I have testified  
25 include revenue requirements, rate design, cost-of-capital, nuclear decommissioning,  
26 accounting deferrals, adjustment mechanisms, income taxes, capital recovery, universal  
27 service funding, and other specialized topics.

28  
29 **Q. WHO DO YOU REPRESENT IN THIS PROCEEDING?**

30 A. As a member of the Office of Consumer Advocate, I represent the interests of Wyoming  
31 citizens and all classes of utility customers in this public utility matter, as required by

1 W.S. § 37-2-401. It is neither my intent nor my charge to represent the position of any  
2 individual, group, municipality, or corporation.  
3

4 **Q. WHAT COURSE OF ACTION IS AVAILABLE TO INDIVIDUAL CONSUMERS**  
5 **OR OTHER INTERESTED PARTIES IF THEY WISH TO PURSUE ISSUES**  
6 **NOT ADDRESSED BY THE OFFICE OF CONSUMER ADVOCATE, OR TAKE**  
7 **A DIFFERENT POSITION FROM THE OFFICE OF CONSUMER ADVOCATE?**

8 A. Consumers and other parties may intervene in the proceedings and raise additional issues  
9 not addressed by the Office of Consumer Advocate, and may take different positions than  
10 those presented by the OCA. Consumers may also present written or oral comments at  
11 the hearing, which then become part of the record in the case and are available to the  
12 Commission as it makes its decision on any particular proposal or suggested change. The  
13 OCA encourages the participation of the public and all interested parties in cases before  
14 the Commission.  
15

16 **Q. ARE YOU SPONSORING ANY EXHIBITS OR SCHEDULES AS PART OF**  
17 **YOUR DIRECT PREFILED TESTIMONY IN THIS PROCEEDING?**

18 A. Yes. I am sponsoring OCA Schedule DKP-1 through DKP-18. These schedules have  
19 been prepared by me. OCA Schedule DKP-1 provides a summary of the OCA's revenue  
20 requirement recommendation in this case compared to the overall requested revenue  
21 increase of Rocky Mountain Power. OCA Schedule DKP-2 is a summary of Rocky  
22 Mountain Power's and the OCA's income statement computations and contains a  
23 summary of OCA's revenue and expense adjustments. OCA Schedule DKP-3 is a  
24 summary of the Rocky Mountain Power and OCA rate bases and the adjustments that  
25 OCA is recommending to the components of rate base. Finally, OCA Schedules DKP-4  
26 through 18 contain additional detail on each of the adjustments shown on the OCA  
27 income statement and rate base schedules. I will further explain each of these schedules  
28 below within the context of the testimony in which they are referenced.  
29

30 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

1 A. The purpose of my testimony is to present the OCA's concerns and recommendations  
2 regarding the overall level of revenue increase that Rocky Mountain Power is requesting  
3 in this case. In other words, the focus of my testimony in this proceeding is on the  
4 revenue requirement. My testimony is part of an overall package of testimony being  
5 presented by members of the OCA.

6  
7 **Q. WHAT IS THE OCA'S OVERALL REVENUE INCREASE**  
8 **RECOMMENDATION IN THIS CASE?**

9 A. While Rocky Mountain Power is requesting an overall increase in Wyoming customers'  
10 rates of just over \$36 million per annum, the OCA recommends the increase be limited to  
11 about \$14.9 million per annum. The derivation of this amount is shown on OCA  
12 Schedule DKP-1. In very broad terms, the difference between the Rocky Mountain  
13 Power request and the OCA's recommendation is explained with the information on the  
14 following table:

<b>RMP PROPOSED INCREASE</b>	<b>\$36.1 Million</b>
Change in Recommended Return on Rate Base	\$7.5 million
Change in Recommended Rate Base	\$1.2 million
Adjustments to Net Power Costs	\$8.4 million
Adjustments to Increase Other Revenues	\$1.6 million
Adjustments to Decrease Expenses other than NPC	\$2.5 million
<b>OCA PROPOSED INCREASE</b>	<b>\$14.9 Million</b>

15  
16  
17  
18 **Q. WHAT PROCESS DID YOU UNDERTAKE BEFORE ARRIVING AT YOUR**  
19 **RECOMMENDATIONS?**

20 A. In addition to studying the many schedules and workpapers provided by Rocky Mountain  
21 Power with its application, the OCA reviewed a significant amount of additional  
22 information. This information came in the form of data responses to several parties in the  
23 case, including the OCA, the Wyoming Industrial Energy Consumers (WIEC), Questar,  
24 and others. Additionally, the OCA reviewed certain orders from prior proceedings,  
25 certain testimony from prior Wyoming proceedings, selective orders and testimony from  
26 other Rocky Mountain Power states, and other documents of a similar nature. These

1 additional documents were comprised of hundreds, perhaps thousands, of pages of  
2 additional data and information.

3  
4 In addition to reviewing additional documentation, I met with a number of Rocky  
5 Mountain Power employees and subject matter experts during the course of my review.  
6 During these meetings, I was able to ask additional questions, converse about a number  
7 of specific topics – such as Wyoming service quality and investment plans – and often  
8 gather additional background about the purpose and desirability of certain proposals.  
9 These one-on-one discussions were supplemented with a group meeting, e-mails, and  
10 telephone conversations. Finally, I had hours of discussion with my OCA colleagues  
11 about our response to the Rocky Mountain Power proposals in this proceeding.

12  
13 **Q. AS A RESULT OF YOUR INVESTIGATION IN THIS PROCEEDING, ARE YOU**  
14 **COMFORTABLE THAT YOU HAVE THOROUGHLY REVIEWED EACH AND**  
15 **EVERY NUMBER CONTAINED IN THE COMPUTATION OF THE REVENUE**  
16 **REQUIREMENT?**

17 **A.** Absolutely not. The investigation and field work of each case builds upon the work of  
18 past cases. Furthermore, it would take an army of analysts working on only this one case  
19 for months to examine all angles of each issue that is presented. Since those resources  
20 are not available, the best I can do is identify areas of concern that are likely to have the  
21 largest impact on customers' rates and focus on those areas. However, in each case, there  
22 are generally areas of interest left unexplored, lying ripe for discussion in the next  
23 regulatory proceeding.

24  
25 In spite of this, I am comfortable that the package of recommendations that I sponsor  
26 with this testimony is within the range of reasonableness. The OCA's recommendation  
27 for a per annum increase of \$14.9 million is in the public interest, and should be adopted  
28 by the Commission.

29

1 **Q. PLEASE EXPLAIN THE GENERAL NATURE OF THIS CASE, AND HOW IT**  
2 **DIFFERS FROM RECENT ROCKY MOUNTAIN POWER (OR PACIFICORP)**  
3 **WYOMING RATE CASES.**

4 A. PacifiCorp's past Wyoming rate cases have generally be historical in nature, with known  
5 and measurable adjustments applied to the historical data in order to derive generally  
6 representative data for the period of time that the rates are anticipated to be in effect. The  
7 development of the case would begin with the data for a recently completed twelve  
8 month historic period. To that data, adjustments would be made to remove items that did  
9 not truly belong within that period (e.g., prior period adjustments) and to recognize  
10 changes that were expected to occur within the upcoming rate effective period (e.g.,  
11 proforma adjustments such as wage increases or changes in power costs). With these  
12 adjustments, an attempt was made to modify the historic earnings and investment period  
13 to make it look like what was expected to occur in the initial period for which rates were  
14 anticipated to be in effect (i.e., the rate effective period).

15  
16 Furthermore, in recent years, most of the PacifiCorp rate filings have been based on the  
17 investment levels at the end of the test year, rather than using the average investment base  
18 for the test period. Moving to the end of the test year was seen as a positive response to  
19 concerns about regulatory lag. For a utility whose investment base is growing, the use of  
20 a year-end test period (as opposed to an average test year) allowed for the recovery of  
21 investment and return on that investment sooner, thus mitigating some of the earnings  
22 erosion that would occur if the allowed return on that new investment was delayed. For  
23 PacifiCorp, in the Wyoming jurisdiction, it became a standard practice to utilize a year-  
24 end rate base rather than an average rate base.

25  
26 The test year and revenue requirement computation used in this case are different from  
27 that described above in two significant ways. First, the company has gone to a forecast  
28 test year with adjustments, rather than using a more historical test year as the starting  
29 point for the revenue requirement. Second, an average rate base is used in this case,  
30 rather than a year-end point of measurement for investment upon which to earn a return.  
31 Both of these changes are founded in the language of the Stipulation and Agreement in

1 Docket No. 20000-230-ER-05, approved by Commission Order issued March 24, 2006.

2 Paragraph 29 of the Stipulation and Agreement states:

3 The Parties stipulate on a one-time trial basis only that in the first general  
4 rate case filed by the Company following Commission approval of this  
5 Stipulation the Parties to this agreement shall support the principle of a  
6 forecast test year that extends 20 months past the date of actual historic  
7 data included in the general rate case application. The Company agrees to  
8 file for informational purposes with the Commission, the Parties and any  
9 other parties to such general rate case, as soon as such information  
10 becomes available, actual normalized costs on a total Company basis for  
11 the time period six months beyond the date of actual data included in the  
12 general rate case application. Nothing herein shall be construed to limit  
13 any Party's right to challenge the forecast methodology, assumptions or  
14 data in that case. The Company agrees to file with the Commission and  
15 other Parties, fully normalized and adjusted historic twelve month results  
16 of operations reports on a semiannual basis as soon as such information  
17 becomes available for informational purposes.  
18

19 **Q. IS THERE STILL A HISTORICAL ASPECT TO THE DEVELOPMENT OF THE**  
20 **TEST YEAR DATA IN THIS CASE?**

21 A. Yes. In developing its future test year, Rocky Mountain Power began with a historical  
22 test period of the twelve months ending December 31, 2006. As with prior cases based  
23 on historical test years, adjustments were made to the 2006 historic base period to remove  
24 non-recurring items, remove costs not permitted to be recovered in customer rates, and  
25 the like. To this adjusted base period, additional adjustments are made to bring the  
26 revenues, expenses, and investment forward in time, in order to represent the future test  
27 period. The future test period that is claimed to be represented by this iterative process of  
28 adjustments is the twelve months ended August 31, 2008.  
29

30 **Q. WHAT MAKES THIS TEST PERIOD AN AVERAGE TEST PERIOD RATHER**  
31 **THAN AN END OF YEAR TEST PERIOD?**

32 A. As described earlier, within an end of year test period, the investment levels have  
33 generally been adjusted to reflect investments that are made up to the end of the year and  
34 those investment amounts include an annualized cost for the return, the depreciation, and  
35 so forth. In many cases in the past, the investment level has even been reflected beyond  
36 the end of the stated test year, such that investments that are placed into service as late as

1 the time of the hearing or even as late as the beginning of the rate effective period are  
2 included in the computation of customers' rates. For example, if a year-end rate base had  
3 been used in this case, a full twelve months of costs related to any plant and equipment  
4 placed in service as of August 31, 2008, would have been included in the rate  
5 computation. But, because an average test year was used rather than a year end test year,  
6 that is not how the investment figures were included in the revenue requirement.

7  
8 **Q. HOW WAS THE INVESTMENT INCLUDED UNDER THE AVERAGE TEST**  
9 **YEAR CONCEPT?**

10 A. It is true that any investment expected to be used and useful and providing service to  
11 customers by August 2008 was included in the computation of rate base. But, the cost  
12 associated with investment that came into service between September 2007 and August  
13 2008 was prorated, so that only the cost associated with the proportion of time that it was  
14 in service during that period was included. So, if a new piece of equipment was expected  
15 to begin its service life as of January 1, 2008, the depreciation and return associated with  
16 that equipment was only included for eight months – or two-thirds of the annualized cost  
17 was incorporated into the revenue requirement.

18  
19 **Q. IS THE USE OF THE AVERAGE TEST YEAR BETTER FOR CUSTOMERS,**  
20 **SINCE IT TENDS TO INCLUDE LESS COSTS ASSOCIATED WITH THE**  
21 **GROWING INVESTMENT OF ROCKY MOUNTAIN POWER?**

22 A. Perhaps, although it is not a question to which a yes or no answer is easily given. If the  
23 goal is to minimize rates for the near term, then yes, the average test year investment  
24 tends to keep rates lower than does the use of the year end investment, particularly for a  
25 utility with growing investment such as Rocky Mountain Power. However, this sets  
26 aside the arguments that have been made over the years that increased regulatory lag  
27 constrains new investment and hurts credit standings of utilities due to the stronger  
28 probability that authorized returns will not be realized. There is also a potential that  
29 additional rate cases will be necessary on a more frequent basis, in order to offset the  
30 continuing regulatory lag of investment recovery. So, if short-term rate stability is a goal,  
31 then the use of an average test period may not be the best choice. On the other hand,

1 some argue that since the future test year is already incorporating investments that will  
2 not be completed for several more months, to reach even further to incorporate fully  
3 annualized levels of investment is too much of a stretch into the future when compared  
4 with average test years. The issue is not a simple one.  
5

6 **Q. HOW DOES THE MATCHING PRINCIPLE ENTER INTO THIS DISCUSSION**  
7 **OF THE AVERAGE VERSUS YEAR END TEST PERIOD?**

8 A. In general, theory argues that an average test period is a better match of all of the  
9 expenses, revenues, and investments in a case, particularly where each of these elements  
10 tends to grow at a reasonably similar pace. So, unless there were some unusual event that  
11 had been identified that warranted an adjustment, expenses would be included at the  
12 amount for January, the amount for February, etc., and then each of these amounts would  
13 be summed. Thus, the expense changes throughout the year based on normal changes to  
14 the economy, but the amount in the last month of the test year is not multiplied times  
15 twelve to derive the annual test year amount, as is the case with annualizing year end  
16 investment in a non-average test period. Or, is it? More and more expenses are being  
17 adjusted within the test year to reflect annual amounts of changes to that expense. This is  
18 the most common with salaries and wages, but is now also frequently done for pensions,  
19 insurance, and other large expenses. It appears that any pure theoretical construct for  
20 average versus future test years has been decimated based on the sheer number of  
21 expense adjustments that are made to each case.  
22

23 **Q. DOES THE CONCEPT OF TRYING TO MATCH THE REVENUE**  
24 **REQUIREMENT TO THE PERIOD FOR WHICH RATES ARE EXPECTED TO**  
25 **BE IN EFFECT ALSO HAVE A ROLE IN THIS DISCUSSION?**

26 A. Yes. While an important principle behind the use of a test year is the matching of  
27 expenses, revenues, and investments, it is not the only principle that should be  
28 considered. Regulators and utilities should also consider whether the computed revenue  
29 requirement is reasonably representative of the time period that rates are anticipated to  
30 take effect. It is not clear to me that the average test year, as used in this case,

1 accomplishes the matching of the revenue requirement to the 2008-2009 timeframe for  
2 which these rates are expected to be in effect. I will explain.

3  
4 Rocky Mountain Power's service territory is in the midst of a significant load growth  
5 period that is in the early stages of really ramping up. As described in Rocky Mountain  
6 Power's testimony, more than 500 MW of new load is expected to be added to the  
7 Wyoming system within the next few years. In order to meet this new load, new  
8 investments are being made and additional expenses are being incurred. But, the data is  
9 lacking in this case as to whether the growth in load, investment and expenses are all  
10 growing at the same pace, such that the revenue requirement formula is not skewed by  
11 disproportional growth in one of those three elements compared to the others. If, for  
12 instance, load is growing faster than investment, without an adjustment to annualize the  
13 revenue associated with that new load, rates may be overstated. Alternatively, if the new  
14 investment is coming on-line earlier than the ramp-up of the new revenues, rates may be  
15 understated if the new investment is not annualized into the revenue requirement. It is  
16 impossible for me to tell based on currently available data, whether rates are more likely  
17 understated, overstated, or neither based on the use of the average test year.

18  
19 **Q. DID ROCKY MOUNTAIN POWER PROVIDE SOME LIMITED**  
20 **INFORMATION TO YOU SHOWING THAT IF A YEAR END TEST YEAR HAD**  
21 **BEEN USED, THE RATE REQUEST WOULD HAVE BEEN SUBSTANTIALLY**  
22 **HIGHER THAN IT IS IN THIS PROCEEDING?**

23 **A.** No, not exactly. Rocky Mountain Power provided a high level summary developed from  
24 the recently filed Utah rate case that shows as we move forward in time the rate base  
25 continues to grow from new investments being made, while third party revenues decline  
26 as a result of expiring wholesale contracts. It also shows that customer revenues continue  
27 to grow. However, the information provided continues to be based on the average test  
28 year concept, and thus, does not address the issue of how the results would be different if  
29 a year end test period had been used for either the Wyoming test period (ended August  
30 2008) or the Utah test period (ended June 2009).

31

1 **Q. DOESN'T THE STATEMENT THAT YOU MADE ABOVE ABOUT THE**  
2 **MISSING INFORMATION IN THIS CASE CONFLICT WITH YOUR EARLIER**  
3 **ASSURANCE TO THE COMMISSION THAT THE RATES YOU ARE**  
4 **RECOMMENDING ARE WITHIN THE RANGE OF REASONABLNESS?**

5 A. No, based on two reasons. First, there is a large range of reasonableness that is  
6 associated with the development of rates based on the subjective nature of the process  
7 and the judgment left to the Commission. So, as is always the case, I would be more  
8 comfortable with my recommendations in this case if I had more information. But, every  
9 day decisions must be made based on imperfect information. I made my recommendation  
10 based on the information available to me and based on the application to which I am  
11 responding. Second, the rates resulting from this case are expected to be in effect for  
12 only a short period of time, as Rocky Mountain Power has already announced its  
13 expectation of filing another Wyoming rate case by midyear 2008. So, even if the  
14 decisions in this case are skewed by the data and the decisions that have been made about  
15 the test year, those decisions can be remedied on short order with different data in the  
16 next case if the Commission has the same test year concerns that I have expressed in this  
17 matter.

18  
19 **Q. DO YOU THINK THAT THE STIPULATION AND AGREEMENT THAT YOU**  
20 **CITED EARLIER WOULD HAVE PERMITTED THE USE OF A YEAR END**  
21 **TEST PERIOD?**

22 A. As is often the case, in hindsight, the language does not appear to address the issue head-  
23 on, leaving room for interpretation. Rocky Mountain Power chose to be conservative in  
24 its interpretation and in doing so, avoided any potential allegation that it violated the  
25 concept of extending its forecast no more than "20 months past the date of actual historic  
26 data." Others interpret the language differently, and in doing so, argue that a year end  
27 test period is permitted by the language.

28  
29 **Q. IS THERE ALSO A VERY REAL EXPENSE IMPACT FROM THE USE OF THE**  
30 **FUTURE TEST YEAR THAT OCCURS IN THIS CASE?**

1 A. Yes. As discussed above, the use of the average test year does not reflect all investments  
2 in the case for a full twelve month period, nor does it reflect the revenue associated with  
3 all of the Wyoming load growth for the full year. Additionally, there are certain expense  
4 increases and *expense decreases* that are not reflected for the full year. One of these  
5 expense decreases is tied to depreciation expense which is expected to decrease in 2008  
6 compared to prior years, based on pending requests before the Commission. Based on  
7 the average test year concept, only 2/3 of the expected decrease is reflected in the case.

8  
9 The response to WIEC data request 7.33 provides an additional example of decreasing  
10 costs that are not fully reflected in the case based on the strict adherence to only  
11 reflecting expenses for the actual test year, and not normalizing the known changes that  
12 occur part way through the test period. WIEC data request 7.33 asks for information  
13 about pension expense for various periods. The response indicates that the 2007 calendar  
14 year pension expense was forecast to be \$51.4 million while the 2008 forecast is \$43.3  
15 million. Yet, the amount included in the test year is \$46 million, based on 1/3 of the  
16 2007 costs and 2/3 of the 2008 cost, leaving out of the rate determination part of that  
17 forecasted decrease in expense.

18  
19 **Q. MS. PARRISH, WHAT CONCLUSIONS AND RECOMMENDATIONS DO YOU**  
20 **OFFER AS A RESULT OF YOUR DISCUSSION ABOUT THE TEST YEAR IN**  
21 **THIS CASE?**

22 A. Given the status of the case, it is reasonable to proceed with the use of the average test  
23 year for the period ending August 2008. My adjustments reflect my attempt to recognize  
24 that this case is based on an average test year, and I have done nothing intentional,  
25 relative to my revenue requirement computation, to try to modify that fact. As Rocky  
26 Mountain Power has committed to the filing of semi-annual reports, the Commission  
27 should be able to monitor any unintended consequences that may arise during this  
28 turbulent growth period in Wyoming.

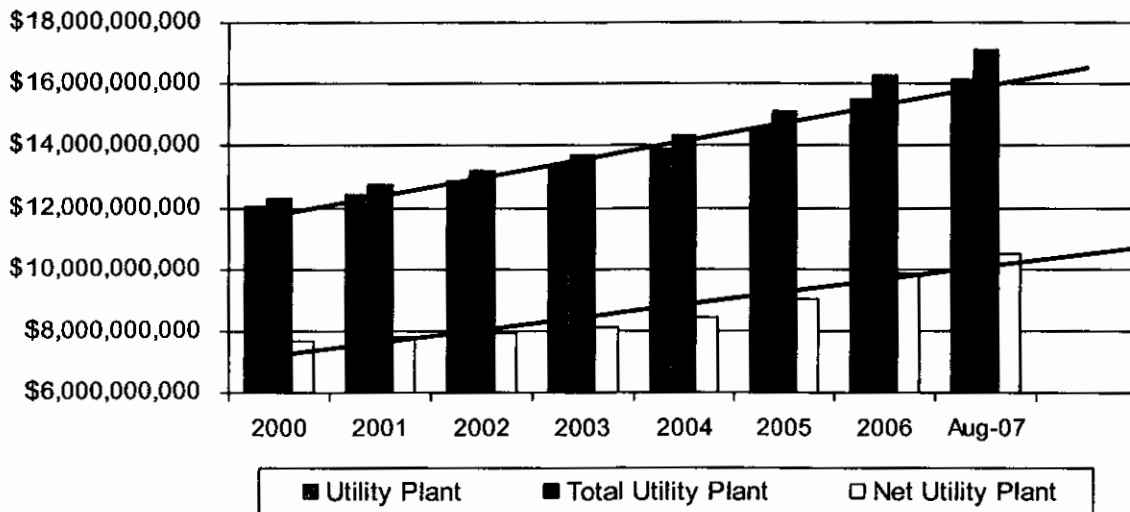
29  
30 Yet, my discussion does provide an opportunity for the Commission to weigh in on this  
31 matter, should it choose to do so, prior to the filing of the next Rocky Mountain Power

1 rate case. The Commission could offer its thoughts on its preference for a year-end or  
 2 average test year. It could offer its thoughts on historical versus future test years. It could  
 3 also offer its thoughts on the type of information that would be useful to address this  
 4 issue in the next case. While the parties agreed not to contest the use of a future test year  
 5 only on a one-time trial basis, as part of the last Stipulation and Agreement, this issue is  
 6 not likely to go away at the conclusion of this case. The OCA would welcome any  
 7 direction that the Commission decides to provide on this matter.  
 8

9 **Q. SEVERAL OF YOUR COMMENTS ABOVE INCLUDED STATEMENTS**  
 10 **ABOUT THE GROWING LEVEL OF INVESTMENT BY ROCKY MOUNTAIN**  
 11 **POWER AND PACIFICORP. HAVE YOU PREPARED AN ANALYSIS OF THIS**  
 12 **GROWTH IN INVESTMENT?**

13 A. Yes. As was anticipated with the change in ownership between Scottish Power and Mid-  
 14 American Energy Holdings Company, new investment in the system is starting to occur.  
 15 This is illustrated with the following chart<sup>1</sup> that shows the growth in net utility plant  
 16 balances for PacifiCorp:  
 17

**Growth in Utility Plant Starting in Year 2000**



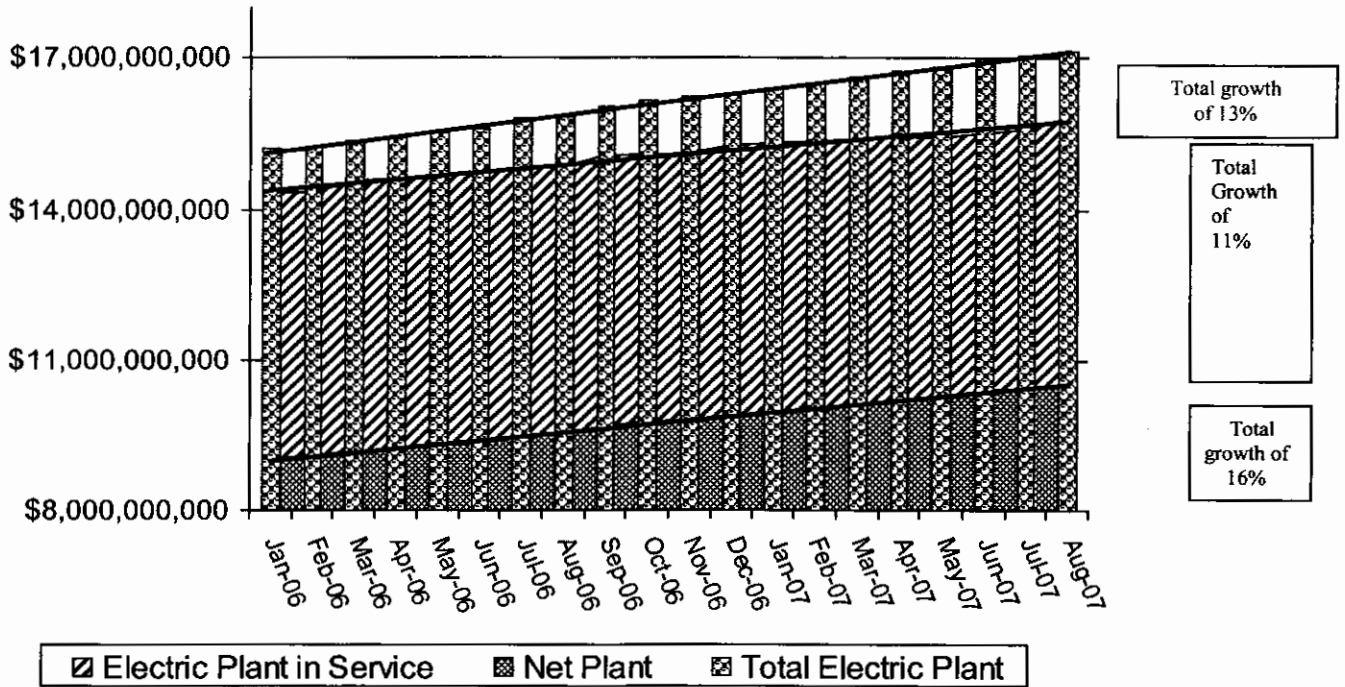
Net Plant grew more between the end of 2005 and August 2007 as it did between the end of 2000 and 2005.

18

<sup>1</sup> Gross and Net Plant data taken from the FERC Form One Reports filed by PacifiCorp as well as the monthly internal Financial and Operating Reports of PacifiCorp. These numbers represent total company numbers for electric utility plant.

1  
 2 I have also looked further at the growth for the period since January 2006 and have  
 3 charted the month end plant balances<sup>2</sup>, as shown below:

**Growth in Total Company Plant Starting in January 2006**



4  
 5  
 6 These charts show that there has been substantial growth in both plant in service and net  
 7 plant over the past two years. Based on current information, this trend is expected to  
 8 continue for the next several years.

9  
 10 **Q. ARE YOU CONTESTING THE RECOVERY OF THIS INVESTMENT**  
 11 **GROWTH IN THIS CASE?**

12 **A.** No, not in general. While the explanation of my adjustments will describe certain  
 13 adjustments to rate base, none of them are related to new projects that have been, or are  
 14 expected to be included in plant in service during the test year. The most significant of  
 15 my rate base adjustments are to items other than tangible assets, such as gross electric  
 16 plant in service. In fact, the OCA is pleased to see additional, prudent investment in hard

<sup>2</sup> Total Utility Plant includes Construction Work in Progress and not only Plant currently in service.

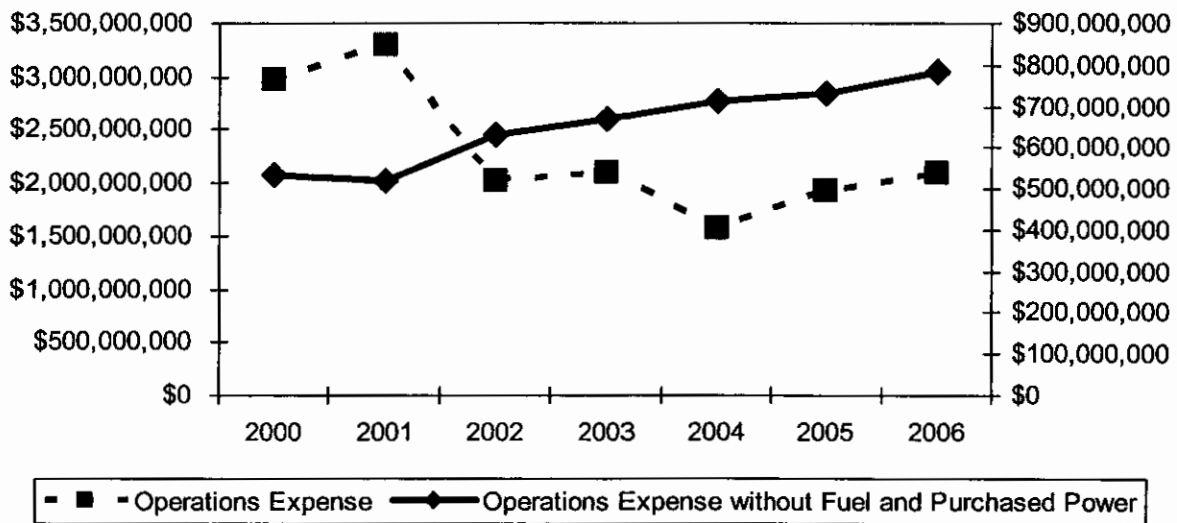
1 assets by PacifiCorp and Rocky Mountain Power, after a number of years of limited  
2 growth in the system. Our largest disappointment is that there is not a reflection in this  
3 case of more company-owned base load (e.g., coal-fired) generating assets in the plant-  
4 in-service.

5  
6 We do, however, recognize that the growth in plant and equipment is one of the causes of  
7 the proposed increase in this case. All other things being equal, each ten million dollar  
8 increase in rate base results in a \$1.32 million increase in revenue requirement, based on  
9 the OCA's recommended cost of capital in this case. In strictly comparing the current  
10 Wyoming filing (test year ended August 2008) with the prior Rocky Mountain Power  
11 Wyoming rate case filing (test year ended September 2006), rate base has increased by  
12 more than \$250 million. *Absent any changes in revenue or expenses or questions of*  
13 *prudence*, this change in rate base would have resulted in a required rate change of \$33  
14 million.

15  
16 **Q. HAVE THERE ALSO BEEN CHANGES IN REVENUES AND EXPENSES?**

17 A. Of course. I did not chart the changes in either total company or Wyoming customer  
18 revenues for the same period over which I examined plant. However, I have done some  
19 analysis of operations and maintenance expenses on a total company basis for the past  
20 several years. Since total operations expense include the cost of fuel and purchased  
21 power, I have found it is often more meaningful to examine operations costs with and  
22 without fuel and purchased power. My high level analysis is shown on the chart below:

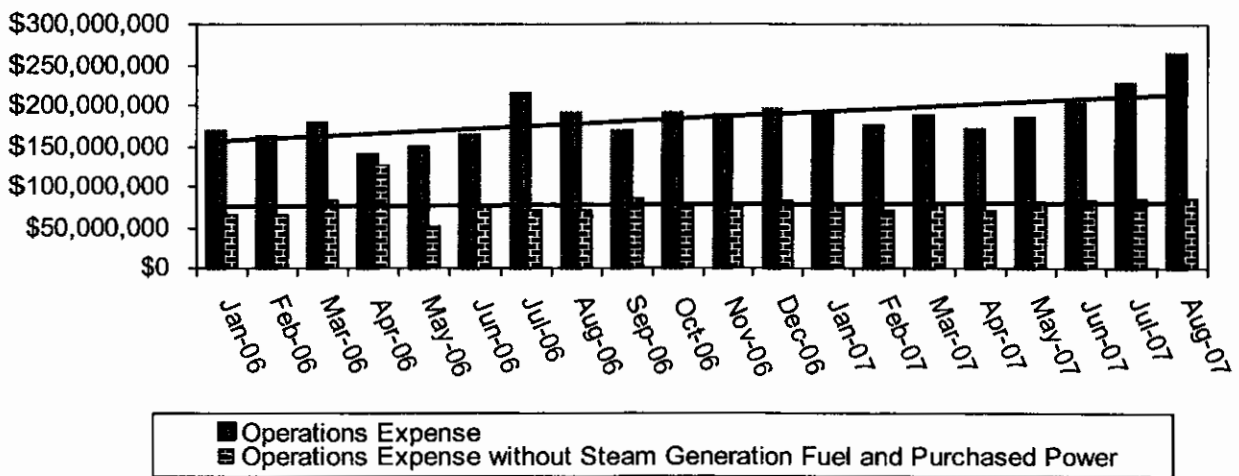
### Annual Total Company Operations Expense



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This chart shows that total operations expense has declined over the past six years, as is expected given the electricity crisis that occurred in the western United States around the turn of the century. However, a slight upturn is seen in the most recent years. As to operations expense excluding fuel and purchased power, it has increased over the charted period. However, the more recent period shows that the operations costs excluding fuel and purchased power, is relatively flat, as shown below:

### Total Company Operations Expense

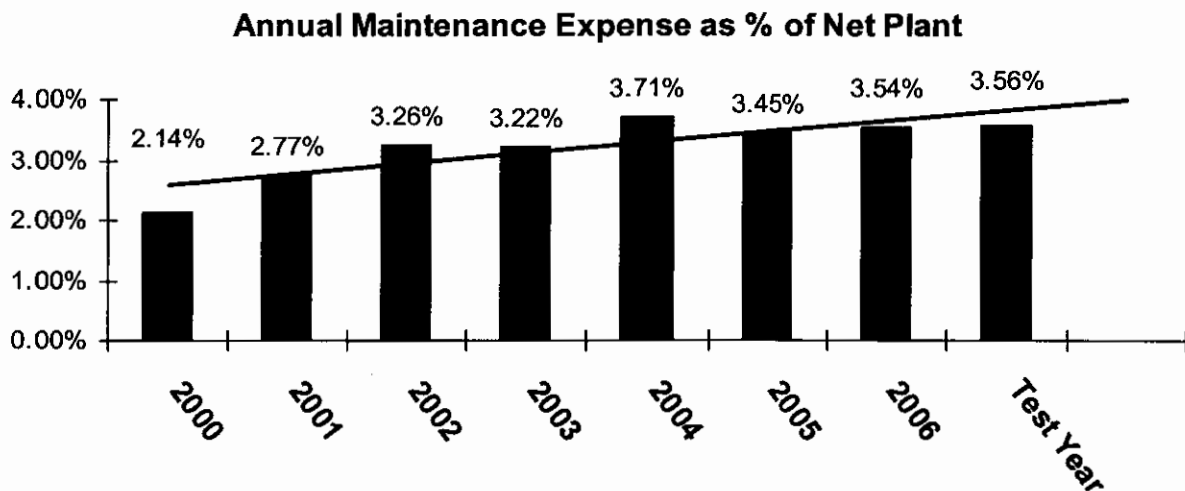


8  
9

1 As a result of this analysis, I chose not to make a broad, wholesale change to total  
2 operations expenses. Instead, I looked at individual matters and made adjustments to  
3 single issues, rather than challenging the overall scope of the costs.  
4

5 **Q. WHAT HIGH LEVEL ANALYSIS DID YOU PERFORM OF MAINTENANCE**  
6 **COSTS?**

7 A. With new plant being added at a substantial pace, as described above, I took a slightly  
8 different approach to my analysis of maintenance costs. I examined the annual cost of  
9 maintenance and compared it to net plant. I then charted these ratios to examine the trend  
10 and to see how the test year maintenance percentage compared to those of prior years.  
11 The results are shown below:  
12



13 While there has been an upward trend in maintenance costs relative to net plant over  
14 time, recent years show some stabilization of these costs. Based on this analysis, I chose  
15 not to make any adjustment to the overall level of maintenance costs of Rocky Mountain  
16 Power in this case. However, this is an area worth watching over the next few years.  
17 Particularly, the Commission may wish to gather additional information as to whether  
18 maintenance costs should actually be decreasing since many believe that new plant  
19 requires less maintenance than does older plant.  
20  
21

1 **Q. MOVING ON TO YOUR ADJUSTMENTS AND THE DETAILS OF YOUR**  
2 **RECOMMENDATIONS, PLEASE DESCRIBE OCA SCHEDULE DKP-2.**

3 A. OCA Schedule DKP-2 is a two page schedule that focuses on Revenues, Expenses, and  
4 Operating Income. The first column of numbers on page one restates Rocky Mountain  
5 Power's filed position prior to any increase in customer rates resulting from this case.  
6 The next sixteen columns of numbers, on pages 1 and 2, summarize the impact of the  
7 OCA's income related adjustments on the Operating Income. Each of these adjustments  
8 is then detailed on a later exhibit, with the exhibit number referenced at the top of each  
9 column. The final column on page two of the exhibit then summarizes the OCA position  
10 prior to any rate increase. Overall, Rocky Mountain Power has computed that without a  
11 rate increase its Wyoming regulated utility operating income for the twelve months ended  
12 August 2008 is anticipated to be just under \$83 million. This compares to the OCA  
13 figure of about \$90.6 million. Some of the OCA adjustments are made because we  
14 believe that the costs should not be recovered from ratepayers – not necessarily because  
15 the costs are not expected to be incurred. This difference in computed net income for the  
16 test year has a significant impact on the amount of rate increase that each party believes is  
17 required as a result of this case.

18  
19 **Q. PLEASE BEGIN TO WALK THROUGH EACH OF YOUR PROPOSED**  
20 **ADJUSTMENTS.**

21 A. My first adjustment, detailed on the eight pages of Confidential OCA Schedule DKP-4, is  
22 to modify the calculation of escalating Operations and Maintenance costs with  
23 information from Global Insights. This schedule is confidential as it contains detailed  
24 Global Insights information that was provided to me on a proprietary basis. To set the  
25 stage for explaining my adjustment, I will first provide an overview of Rocky Mountain  
26 Power's adjustment which is modified by this particular OCA adjustment.

27  
28 In order to modify its 2006 adjusted base year operations and maintenance costs into  
29 projected test year costs, Rocky Mountain Power made the adjustment detailed in Mr.  
30 McDougal's Schedule SRM-2, Section 4. The Company first removed labor from the  
31 base operations and maintenance costs, since it is escalated separately. Then, other

1 operations and maintenance cost adjustments were removed in order to arrive at a bare-  
2 bones base cost that may then be escalated. An escalation factor taken from the Global  
3 Insight's information is then applied to the base number. This arrives at the escalated test  
4 year operations and maintenance costs for the test year.

5  
6 I went through a similar process, but at a different level of detail with a different set of  
7 escalation factors. The first difference in the calculation relates to the level of detail  
8 undertaken in the calculation. Rocky Mountain Power did not remove labor costs at a  
9 detailed, account-by-account level, but instead took these costs out of only a few  
10 accounts. I went through a more detailed process of removing the labor associated with  
11 each account from each account, rather than through a more consolidated adjustment.  
12 This is shown on Column B of OCA Schedule DKP-4.

13  
14 Second, I used a more detailed set of escalation factors than did Rocky Mountain Power.  
15 As shown on page 4.0.6 through 4.0.9 and page 4.17.1 of Mr. McDougal's Schedule  
16 SRM-2, the Company used the Global Insight's forecasts dated the 4<sup>th</sup> Quarter of 2006.  
17 The escalators used were to predict the costs for 2006 and 2007, with a weighting of 2/3  
18 costs for 2006 and 1/3 for 2007. Rocky Mountain Power also used escalators that were  
19 already grouped by type of account rather than applying the individual escalators for each  
20 account.

21  
22 My escalation calculation used a more recent forecast than that used by Rocky Mountain  
23 Power. I used a forecast that is found in the report labeled 2<sup>nd</sup> Quarter of 2007. I found it  
24 appealing to use the most current thinking of Global Insights as their view changes from  
25 time to time, as it is important to obtain their most recent thinking relative to what cost  
26 changes are likely to ensue. Additionally, I used the forecast for the period for 2008,  
27 rather than for earlier periods used by the Company. It was more logical to me to use the  
28 2008 forecast, as that is the period for which the rates are expected to be in effect. The  
29 remainder of the calculation is the same as performed by Rocky Mountain Power.

30

1 **Q. PLEASE DISCUSS THE GLOBAL INSIGHTS ESCALATORS AND YOUR**  
2 **COMFORT WITH THEIR USE IN THIS CASE.**

3 A. During my investigation of this case, I took the opportunity to speak with a representative  
4 of Global Insights to better understand the process of deriving the escalators. While I am  
5 not an expert on the process, I was impressed with the expansive information that is  
6 tracked and the formulistic nature of deriving each escalator for nearly every account  
7 used by electric utilities. Furthermore, the example given to me made a lot of sense:  
8 Escalators for supervision and engineering are based on employment cost indices as well  
9 as CPIs related to transportation and travel. I do not have cause to take issue with Global  
10 Insights or its results because of the limited information that I have and because the  
11 information that I do have seems reasonable.

12  
13 I am more concerned about how Rocky Mountain Power applied those Global Insight  
14 escalators in this case.

15  
16 **Q. PLEASE EXPLAIN YOUR CONCERN.**

17 A. To provide some context for my concern, I wish to first provide additional information  
18 about the Global Insights data. Approximately once each quarter, Global Insights  
19 releases, on a paid subscription basis, a forecast for nearly every operations and  
20 maintenance account that is mandated to be utilized by each electric utility – accounts  
21 contained within the mandated Federal Energy Regulatory Commission (FERC) Uniform  
22 System of Accounts (USOA). Additionally, forecasts at a more consolidated level are  
23 offered. These consolidated numbers are offered for groups of accounts (e.g., Operations  
24 and Maintenance for Steam Production Accounts), groups of accounts with a separate  
25 factor for Operations and a separate factor for Maintenance, and finally, a high level  
26 consolidated Operations and Maintenance cost forecast factor is offered.

27  
28 These forecasts are not just for the upcoming year but are for each of many years into the  
29 future. For example, the 1<sup>st</sup> Quarter 2005 Forecast contains an individual forecast for  
30 each year for the period of 2002 through 2030. (I presume the 2002, 2003 and 2004

1 numbers are historical actuals.) Thus, the forecast for any particular year will change  
2 over time, and the change may be dramatic, as shown in the chart below:

3

4 **Begin Confidential**

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10 **End Confidential**

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17

Rocky Mountain Power chose to use a blend of the 2006 and 2007 forecast taken from the 4<sup>th</sup> Quarter of 2006 publication. As shown above, the 2006 and 2007 forecasts tend to show higher predicted cost increases when compared with the predicted results for the year of 2008. The OCA chose to use the forecast for 2008 taken from the 2<sup>nd</sup> Quarter of 2007 publication. While it is a benefit for customers that the 2008 escalation factors are less than those used by the Company, that is not the reason they were selected. Based on

1 trying to match costs to the rate effective period, and based on obtaining Global Insight's  
2 latest thinking as to the likely costs, the 2008 period was selected. The difference is  
3 reflected in our calculation of the Operations and Maintenance escalation adjustment.  
4 After consideration of the income tax affect of reducing expenses, the OCA adjustment  
5 impacts the pre-rate increase Operating Income by about \$456,000.  
6

7 **Q. ARE YOU RECOMMENDING A SECOND ADJUSTMENT THAT INVOLVES**  
8 **THE USE OF GLOBAL INSIGHTS FACTORS?**

9 A. Yes. A very small adjustment is being made simply to be consistent with the larger  
10 adjustment described above. The adjustment is to Incremental Operations and  
11 Maintenance Costs and is shown on Confidential OCA Schedule DKP-10. The only  
12 difference from the adjustment made by Rocky Mountain Power (shown on Mr.  
13 McDougal's SRM-2, page 4.6.1) is the Global Insights escalator applied. As I did in the  
14 above described adjustment, I used the 2<sup>nd</sup> Quarter 2007 escalator for the period of 2008.  
15 The Wyoming allocated portion of this adjustment is less than \$20,000.  
16

17 **Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO DEPRECIATION EXPENSE.**

18 A. This adjustment (detailed on OCA Schedule DKP-5) is again an adjustment to the  
19 calculation and forecast made by Rocky Mountain Power that is already included in the  
20 case at Schedule SRM-2, Section 6. I began with the Company's calculation that is based  
21 on the proposed changes to depreciation that are somewhat different from those contained  
22 in the September 31, 2007, application of Rocky Mountain Power in Docket No. 20000-  
23 257-EA-06. The amount of depreciation expense is also slightly different than the  
24 amount that is currently being discussed as a potential six-state settlement of the  
25 depreciation case. The adjustment that I am proposing is a best estimate of mine and  
26 Rocky Mountain Power's of the likely outcome of the six-state settlement. However,  
27 since that agreement has not yet been finalized and has not yet been approved by the  
28 Commission, it is possible that an additional adjustment will be required to be made prior  
29 to the end of the case in order to synchronize any authorized depreciation rate changes  
30 and the depreciation expense included in the revenue requirement.  
31

1 As OCA Schedule DKP-5 shows, the proposal contained within the Company's  
2 application would have reduced depreciation rates by about \$19 million annually on a  
3 total company basis. This proposed reduction is based primarily on lengthening the lives  
4 of the Company's generating plants in recognition that those plants are being refurbished  
5 and kept in use substantially longer than some of their originally estimated lives. A  
6 number of other changes were also built into the Company's depreciation expense  
7 estimate including additional investment to be depreciated, issues surrounding the  
8 relicensing of hydraulic generating units, and recognition of higher costs of removal than  
9 in the past.

10  
11 The not yet finalized resolution of the on-going depreciation case is expected to further  
12 reduce the total company depreciation expense by about \$8.8 million. This potential  
13 settlement tweaks some of the adjustments originally anticipated to be made to the lives  
14 of the generating plants, but also results in decreased depreciation expense related to  
15 transmission and distribution plant. My best estimate, based on helpful information  
16 provided by Rocky Mountain Power, is that the Wyoming allocated portion of  
17 depreciation expense should be reduced by an additional \$696,000. Conforming  
18 adjustments have been made to accumulated depreciation expense, accumulated deferred  
19 income taxes, and investment tax credits. All of these items are shown on OCA  
20 Schedules DKP-2 and DKP-3.

21  
22 **Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO THE SO<sub>2</sub> SALES REVENUE**  
23 **AND THE UNAMORTIZED DEFERRED SO<sub>2</sub> REVENUE BALANCE.**

24 A. The adjustments I am proposing related to the sale of SO<sub>2</sub> emission credits are detailed on  
25 OCA Schedule DKP-6, a two page schedule. With this adjustment, I am proposing to  
26 modify the current practice for addressing SO<sub>2</sub> sales revenues, since the information  
27 supporting the current practice has changed and a review of the procedure is warranted  
28 based on current information.

29  
30 Currently, Rocky Mountain Power places the revenue from the sale of the SO<sub>2</sub> credits in  
31 a deferral account at the time of the sale and amortizes the amount over a fifteen-year

1 period. I am proposing that the amount that has been deferred be amortized over a seven  
2 year period in order to assure that customers obtain their rightful benefit of these sales in  
3 a more timely fashion. The OCA adjustment allocates an additional \$707,000 of SO<sub>2</sub>  
4 revenue to the Wyoming jurisdiction.

5  
6 Additionally, I recommend that the deferred amounts be recomputed to recognize the  
7 beginning of the amortization period at the time that the revenue is reflected in rates, and  
8 not at the time of the sale. This is a change from the current computation of Rocky  
9 Mountain Power, where the unamortized amount of the deferral begins to be reduced at  
10 the time of the sale, whether or not the amount of the revenue amortization has been  
11 reflected in the computation of rates. This OCA adjustment reduces the Wyoming  
12 allocated portion of rate base by about \$653,000.

13  
14 **Q. PLEASE PROVIDE SOME HISTORY OF THIS ISSUE.**

15 A. The treatment of the SO<sub>2</sub> revenues was a contested issue in Docket No. 20000-ER-99-  
16 145. In my responsive testimony on behalf of the Consumer Advocate Staff, I advocated  
17 that a three year average of the sales be included in the revenue. PacifiCorp witness Jeff  
18 Larsen, in his rebuttal testimony for that case, starting at page 9 stated:

19 I believe that the CAS proposed adjustment greatly overstates the expected  
20 revenues from emission allowance sales on a going forward basis. The  
21 level of allowance sales during the period of 1994 – 1998 is simply not  
22 reflective of the Company’s expectations for the rate effective period.  
23 Annual sales of emission allowances averaged over \$10.8 million on a  
24 total company basis during the five years between 1994 and 1998, but they  
25 have declined to less than \$0.5 million in 1999. For the period 2000-2005  
26 PacifiCorp expects that its revenue from SO<sub>2</sub> allowance sales will be  
27 limited to the proceeds from EPA auctions which are expected to average  
28 about \$1 million annually on a total Company basis. Thus, the \$9 million  
29 annual amount determined by CAS through its six-year average is based  
30 on historical factors that are no longer part of the Company’s SO<sub>2</sub>  
31 compliance strategy.

32 ...

33  
34 I believe that the Company’s proposed 15-year amortization of actual  
35 1998 allowance sales provides a fair representation of the revenues  
36 expected to be realized on a continuing basis. The use of the 15-year  
37

1 amortization period to match the gain from the allowances to the plant  
2 costs that give rise to the allowances is conceptually superior to the use of  
3 a historical average that ignores the Company's limited supply of  
4 allowances, changing market conditions and the Company's operating  
5 practices.  
6

7 In the Commission Order for Docket No. 20000-ER-99-145, issued May 23, 2000, the  
8 SO<sub>2</sub> sales issue is addressed at paragraph 202(b):

9 Regarding revenues generated by SO<sub>2</sub> emission allowance sales,  
10 PacifiCorp proposed the use of actual sales amounts and the Consumer  
11 Staff proposed a normalized adjustment. Because the sales have fluctuated  
12 in magnitude in the last several years, we do not believe that the facts  
13 support a normalizing adjustment based on a multi-year average.  
14 Although there was some doubt as to whether or not the PacifiCorp  
15 proposal returned 100% of the benefit of the sales to customers, in its  
16 Brief at 47-48, PacifiCorp argues that all of the benefit from these sales  
17 would be returned to customers under its proposal. We accept this  
18 argument and the company proposal which tracts company assets and  
19 amortizes those assets based on actual experience. We do not accept the  
20 Consumer Advocate Staff proposal, but we direct PacifiCorp to  
21 demonstrate in its next rate case exactly how well its mechanism functions  
22 to produce the maximum benefit to [sic] shareholders.  
23

24 Most, if not all, of the revenue requirement issues for PacifiCorp and Rocky Mountain  
25 Power have been settled since the time this contested issue was addressed by the  
26 Commission in 2000, so this appears to be the best direction and guidance provided on  
27 this matter. However, several points relevant to this current case may be gleaned from the  
28 above citations:

- 29 ▪ PacifiCorp assured the Commission that all of the benefit of the sales would be  
30 returned to customers under the PacifiCorp proposal, and this swayed the  
31 Commission in its decision on the treatment of the revenues.
- 32 ▪ The expected sales for the earlier period in question were expected to be less than  
33 \$1 million annually on a total company basis.
- 34 ▪ The 15 year amortization period is tied to the life of the plant and equipment  
35 which gave rise to the sale of the emission allowances.
- 36 ▪ Changing market conditions and operating practices should be taken into account  
37 when determining the appropriate regulatory treatment.  
38

1 **Q. WHAT IS YOUR RECOMMENDATION REGARDING THE SO<sub>2</sub> SALES IN**  
2 **THIS CASE?**

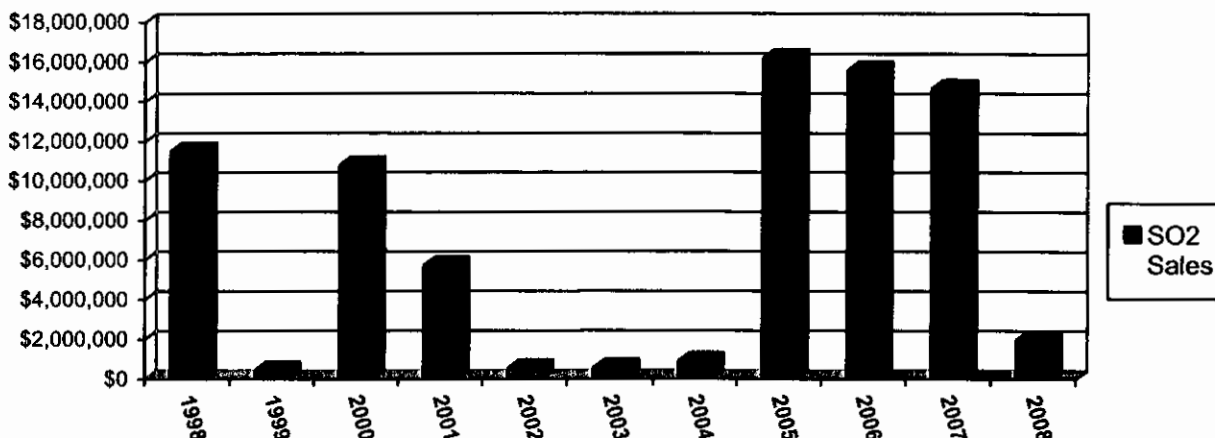
3 A. I suggest that the four points identified above be applied against the current situation to  
4 see if they continue to support the past practice.

5  
6 First is the question of whether the current process actually does assure that 100% of the  
7 sales revenues are returned to customers. Based on Rocky Mountain Power's calculation  
8 shown on Schedule SRM-2, page 3.2.1, the revenues begin to be amortized out of the  
9 deferral account upon completion of the sale. Yet, if that revenue is not reflected in the  
10 revenue requirement computation that is used to establish customer rates, 100% of that  
11 benefit cannot possibly be returned to customers or be used to directly benefit customers.  
12 The PacifiCorp assurance that customers will receive the full benefit of these sales can  
13 only be accomplished if the revenue being amortized is not subtracted from the deferral  
14 balance until that amount of revenue has actually been included in the computation of  
15 customer rates and those rates are approved and in effect. This is precisely what the  
16 OCA adjustment to the SO<sub>2</sub> deferral balance does. The adjustment looks at when various  
17 sales were included in rate filings and when the rates resulting from those applications  
18 took effect. The OCA computation shows that at the beginning of the test year, there is  
19 an unamortized deferred emission allowance sales balance of more than \$65 million,  
20 compared to Rocky Mountain Power's computed balance of about \$51 million on a total  
21 company basis.

22  
23 The second point relates to Mr. Larsen's position in the earlier case that sales for the  
24 upcoming periods were expected to be less than \$1 million per year. In hindsight, the  
25 sales were only that small for three of the years since Mr. Larsen made his prediction,  
26 2002, 2003 and 2004. As detailed on OCA Schedule DKP-6, the average of annual sales  
27 for the period of 1998 through 2008 has been more than \$7 million per year. The 5 year  
28 rolling average for 2007 and 2008 both totaled more than \$9 million and sales in 2005,  
29 2006, and 2007 exceeded \$14 million each year. This history is shown graphically on the  
30 chart that follows.

31

### History of SO<sub>2</sub> Sales Revenue



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Under the Company’s proposal, less than one-third of the actual test year SO<sub>2</sub> revenues would be reflected in the adjusted revenues in the rate calculation in this case. More than one-half of the unamortized deferred balance has been added since February 2006.

The third point is that the 15-year amortization period was tied to the remaining life of the plant and equipment that gave rise to the credits. Some of the proposals in the pending depreciation case would add decades to the remaining lives of power generating plants and its associated equipment, no longer allowing that 15-year remaining life to survive. To keep the theory intact, the amortization period would need to be extended, exacerbating the problem of a growing deferral account without a real accounting or assurance that customers are actually receiving their promised benefits.

Finally, Mr. Larsen pointed to changing market conditions when looking at the appropriate regulatory treatment. Changing markets conditions include what is occurring as part of the Environmental Protection Agency (EPA) auction process for these allowances. In EPA’s 1999 spot auction, the price of a winning bid had to be in excess of \$200 per allowance. At the 2007 EPA spot auction, a winning bid had to exceed \$400. Furthermore, Rocky Mountain Power witness Fehrman describes the major capital project at the Huntington plant that includes the addition of a SO<sub>2</sub> scrubber. (See page 30 of Fehrman testimony.) With the addition of a scrubber, even more allowances should be

1 available to sell in the market. This is another clear change in conditions that should be  
2 taken into account when determining the regulatory treatment of the allowance sales.

3  
4 In light of the changing facts and circumstances described above, I recommend that the  
5 past practice of deferring the emission allowance sales revenue and amortizing the  
6 revenue over a 15-year period be modified. Rather than amortizing the amount over 15  
7 years, I have taken the total remaining unamortized balance and amortized it over seven  
8 years.

9  
10 **Q. HOW DID YOU ARRIVE AT A RECOMMENDED AMORTIZATION PERIOD**  
11 **OF SEVEN YEARS?**

12 A. The seven years is based on my own judgment of a reasonable time frame based on the  
13 data summarized on OCA Schedule DKP-6. The annual average sales for the years 1998  
14 through 2008 is over \$7 million. The five year rolling average for the periods ended  
15 2007 and 2008 is more than \$9 million. Sales in more recent years are exceeding \$14  
16 million annually. The seven year amortization in this case would result in an  
17 amortization for the test period of about \$9.3 million, or about \$4.2 million more than the  
18 amortization included by Rocky Mountain Power in the adjusted test period. On a  
19 Wyoming jurisdictional basis, this results in additional Wyoming revenues of more than  
20 \$700,000.

21  
22 **Q. IS THERE A BASIS TO LABEL YOUR ADJUSTMENT AS CONSERVATIVE**  
23 **(OR UNDERSTATED) FROM THE STANDPOINT OF CUSTOMERS?**

24 A. Yes. In his testimony that accompanies the recently filed Rocky Mountain Power rate  
25 case in Utah (Docket 07-035-93, filed December 17, 2007), Mr. McDougal describes the  
26 treatment of the SO<sub>2</sub> sales for its Utah jurisdiction at pages 28-29:

27 Consistent with the Commission order in Docket No. 97-035-01, the  
28 Company has amortized all sales of emission allowances over a four-year  
29 period.  
30

1 Utah has a four-year amortization period. In this case, I am only recommending a seven-  
2 year amortization period. That could easily be classified as a conservative – not  
3 aggressive – position in this case.  
4

5 **Q. MS. PARRISH, PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENT**  
6 **THAT RELATES TO THE SALE OF RENEWABLE ENERGY CREDITS.**

7 A. The details of this adjustment are shown on OCA Schedule DKP-7 and result in  
8 additional proposed Wyoming revenues of about \$405,000. The adjustment relates to  
9 two separate matters involving the sale of renewable energy credits. The first and more  
10 easily explained matter is that there are expected to be more of these credits to sell over  
11 time, so an adjustment is made to recognize this additional quantity of credits that can be  
12 sold. These additional credits come from the installation of more company-owned  
13 renewable generating resources on the system.  
14

15 The second piece of the adjustment is a matter related to allocations and state policies  
16 relative to renewable portfolios. The recent past practice and current interjurisdictional  
17 allocation agreement calls for the revenues from renewable energy credits to be allocated  
18 system wide across all six states. This means that each state gets a proportional share of  
19 the revenue that PacifiCorp receives from the sales of these renewable energy credits.  
20 This allocation practice was consistent with the practice of treating the renewable energy  
21 credits and the underlying generation assets as system-wide assets that then were  
22 allocated to all jurisdictions. However, PacifiCorp has recently stopped selling the  
23 renewable energy credits that are allocated to California and Oregon, based on the  
24 renewable portfolio standards that have been, or are in the process of being, implemented  
25 in those two states. Instead of selling them, the Oregon and California renewable energy  
26 credits are being held back to fulfill the portfolio standards of the state. With this change  
27 in sales practice, it is natural that the allocation associated with the sales of these credits  
28 should also change. This reallocation is what is reflected as part of this proposed  
29 adjustment. Specifically, the revenues that would otherwise have been allocated to  
30 California and Oregon are redistributed to the remaining jurisdictions (Washington,

1 Idaho, Utah, Wyoming, and FERC). The specific calculation is shown on OCA Schedule  
2 DKP-7.

3  
4 **Q. WHAT IS THE BASIS FOR THE MALIN SPRINGS TRANSMISSION REVENUE**  
5 **ADJUSTMENT SHOWN ON OCA SCHEDULE DKP-8?**

6 A. This adjustment relates to the expiration of a contract for wheeling over the Malin  
7 Springs transmission line. At the time that the application was filed, the outcome of the  
8 negotiations regarding future revenues on this line was still in doubt. It is my  
9 understanding that an agreement has now been reached that will result in approximately  
10 \$20 million of transmission revenues annually. For purposes of this case, based on the  
11 use of the average test year, that \$20 million is only reflected as \$13.33 million on a total  
12 company basis, given that the new contract does not take effect until January 2008. This  
13 compares to the \$10 million of revenues already included in the filing, resulting in a  
14 Wyoming jurisdictional revenue addition of about \$475,000.

15  
16 **Q. PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENT TO REMOVE**  
17 **THE SEVERANCE PAYMENT RELATED TO MS. JOHANSEN, FORMER**  
18 **PRESIDENT OF PACIFICORP.**

19 A. This recommended adjustment has both an income statement impact and a rate base  
20 impact as shown on OCA Schedule DKP-9. I am recommending a \$174,460  
21 disallowance of Wyoming jurisdictional expenses and a \$290,767 reduction of Wyoming  
22 jurisdictional rate base. These adjustments are recommended to recognize that customers  
23 are not receiving a benefit from the severance of Ms. Johansen and this cost should be  
24 borne by shareholders rather than customers.

25  
26 A May 24, 2005 press release announced the intention of MidAmerican Energy Holdings  
27 Company to acquire PacifiCorp from Scottish Power. The press release states, in part:

28 Greg Abel, president and chief operating officer of MidAmerican, said, "I  
29 am pleased to be working with PacifiCorp's great management team and  
30 dedicated employees. I look forward to supporting them in the execution  
31 of their business plans."  
32

1 This press release directly praises management and says nothing about replacing most of  
2 the upper level management team as part of the acquisition.

3  
4 As part of her testimony (in both Wyoming and Utah) supporting the change in  
5 ownership transaction, Ms. Johansen states:

6 MEHC intends to retain PacifiCorp's current management team. This  
7 team, when combined with capabilities of MEHC, will be able to continue  
8 its track record of operational improvements.

9  
10 This statement was made in response to a question about why the proposed transaction  
11 was in the public interest. It was one of the selling points of the transaction and again,  
12 there is a clear indication that current management will be retained. Certainly, when one  
13 thinks of current management, the president of the company would be among those  
14 included.

15  
16 On December 21, 2005, a press release announced Ms. Johansen's intent to leave  
17 PacifiCorp upon completion of the sale to MidAmerican Energy Holdings Company.  
18 The text of the press release follows:

19  
Wed, Dec 21, 2005

**PacifiCorp president and CEO announces decision to leave company  
after completion of sale to MEHC**

PORTLAND, Ore. -- Judi Johansen, president and CEO of PacifiCorp, announced today that she will leave the company after the completion of its sale to MidAmerican Energy Holdings Company in 2006.

Johansen, who joined the company in December 2000, said today, "This is a personal decision, which was made recently. The reason for my decision is to spend more quality time with my family. The decision has been an extremely difficult one as I have thoroughly enjoyed being part of PacifiCorp.

"In making my decision, I concluded that the close of the transaction will be the best time to transition out of my role as president and CEO of PacifiCorp," she added.

20

1 Again, there is no mention about the whole of upper management being replaced. This is  
2 reported as Ms. Johansen's personal decision. While it is true that I often wonder  
3 whether "spending more time with one's family" is the new euphemism for involuntary  
4 separation from one's employment, it would be wrong to read that into this statement  
5 without additional information. And, all of the other information available indicates that  
6 MidAmerican intended to retain and work with the existing PacifiCorp management.

7  
8 It is not until after the close of the MidAmerican transaction that it became clear that a  
9 significant number of management personnel were to be replaced at PacifiCorp. This  
10 became clear from a March 21, 2006, press release where the new management team and  
11 new corporate organization were announced.

12  
13 As found on page 103 of PacifiCorp's Form 10-K for the fiscal year ended March 31,  
14 2006, filed with the Securities and Exchange Commission (SEC),

15 Severance benefits are payable by PacifiCorp for voluntary terminations  
16 as a result of certain alternations in position or compensation that have a  
17 detrimental impact on the executive's employment or involuntary  
18 terminations (including PacifiCorp-initiated resignation) for reasons other  
19 than cause...

20  
21 The Executive Severance Plan also provides enhanced severance benefits  
22 in the event of certain terminations during the 24-month period following  
23 a qualifying change-in-control transaction; with respect to MEHC's  
24 acquisition of PacifiCorp, this qualifying period commenced on May 23,  
25 2005. Executives designated by the PacifiCorp Compensation Committee  
26 or the Chairman, as applicable, are eligible for change-in-control benefits  
27 resulting from either a PacifiCorp-initiated termination without cause or a  
28 resignation generally within two months after certain material alternations  
29 in position or compensation...

30  
31 There is no information provided that indicates that Ms. Johansen's position was being  
32 materially altered or that she was involuntarily terminated. In fact, her public statements  
33 indicate that neither of these stated reasons for receiving termination payments took  
34 place.

35

1 **Q. WHAT DOES ANY OF THIS HISTORY HAVE TO DO WITH YOUR**  
2 **PROPOSED ADJUSTMENT TO SEVERENCE PAYMENTS?**

3 A. First, the wholesale changes to the management team that occurred were not known until  
4 after the transaction. The information provided in the ownership transaction was  
5 different, and may have impacted the overall analysis of that transaction. Second, while  
6 it is the right of the Board of Directors to provide separation payments at their discretion,  
7 the separation of Ms. Johansen does not appear to fit the stated policies for when  
8 separation payments will be made, based on all of the information provided thus far.

9  
10 Third, Rocky Mountain Power witness Erich Wilson explains at page 15 of his direct  
11 testimony that higher severance amounts are necessary because “executives are likely to  
12 need more time than the broad-based employee population to secure a comparable  
13 position with another company.” While I could debate whether or not this is true in the  
14 case of Ms. Johansen and her peers, there is no need to enter that debate, as Ms. Johansen  
15 does not indicate that she is actively seeking comparable employment to the position that  
16 she announced that she voluntarily left.

17  
18 **Q. WHY ARE YOU ONLY CONTESTING THE SEVERANCE PAYMENT FOR MS.**  
19 **JOHANSEN AND NOT FOR THE OTHER MEMBERS OF THE**  
20 **MANAGEMENT TEAM THAT WERE REPLACED AS PART OF THE**  
21 **CHANGE IN OWNERSHIP?**

22 A. There is more public information surrounding Ms. Johansen’s departure, given the  
23 December 21, 2005, press release, than there is regarding the departure of the other  
24 members of the management team. I do not know how many of the departures were  
25 voluntary or involuntary, and that difference is notable in the PacifiCorp compensation  
26 policy.

27  
28 **Q. IS THERE ALSO AN ECONOMIC REASON TO CONTEST THE OVERALL**  
29 **AMOUNT OF THE EXECUTIVE SEVERANCE PAYMENTS THAT HAVE**  
30 **BEEN INCLUDED IN ROCKY MOUNTAIN POWER’S REQUESTED RATES?**

1 A. Yes. Rocky Mountain Power witness Erich Wilson's Schedule EDW-3, page 5 of 5,  
2 shows that for the non-executives that left the employment of the company, the payback  
3 of the cost of severance costs occurs in less than one year through the reduced on-going  
4 payments for salary and benefits. Specifically, the schedule shows that the cutbacks  
5 result in more than \$31 million in on-going annual savings while the severance payments  
6 were about \$28 million. Clearly, customers are not harmed economically by the decision  
7 to pay certain employees for their permanent departure from the company's payroll. The  
8 same is not true when looking at the payments made for the departure of the Company's  
9 executives.

10  
11 Mr. Wilson's Schedule EDW-4 shows a similar analysis for the executive severance  
12 payments. However, the payback through normal payroll savings is more than 3 years in  
13 the case of the executives. The executive severance packages proposed to be deferred  
14 and amortized through customer rates is more than \$11 million for the nine executives  
15 listed. Yet, after backfilling some of these positions, the annual savings of on-going  
16 labor and benefits is only \$3.5 million annually.

17  
18 Under the Company's proposal, it will be more than three years before customers see any  
19 economic benefit from the on-going reductions of the executives' departure. This shown  
20 with the following total company computation:

21	Annual Amortization Cost based on 3 year amortization	\$3,784,835
22	Cost of Including Unamortized Portion in Rate Base	<u>\$1,252,345</u>
23	Cost before offset for on-going payroll savings	\$5,037,180
24	On-going savings	<u>\$3,496,455</u>
25	Cost to PacifiCorp customers during amortization period	\$1,540,725

26  
27 With about 13.4% of this cost being allocated to Wyoming, this severance of executives  
28 would cost Wyoming customers more than \$206,000 annually.

29  
30 I have proposed an adjustment to reduce the executive compensation expense by about  
31 \$174,460 annually and to reduce rate base by \$290,767, both shown as Wyoming  
32 allocated amounts. These translate into a reduction in revenue requirement of about  
33 \$214,000. The adjustments that I propose simply remove any disadvantage to customers

1 of the executive severance plan – it does not actually provide customers with any  
2 economic benefits in this case.

3  
4 **Q. ARE YOU PROPOSING A RELATED ADJUSTMENT TO THE LARGER**  
5 **DEFERRAL OF THESE TRANSITION SEVERANCE COSTS?**

6 A. Yes, and the adjustment is shown on OCA Adjustment DKP-16. As shown on Mr.  
7 McDougal’s Schedule SRM-2, page 4.9, Rocky Mountain Power proposes to include  
8 about \$4.4 million of unamortized Wyoming allocated deferred severance related  
9 transition costs in rate base. The OCA adjustment proposes to eliminate this addition to  
10 rate base. The OCA is suggesting a sharing of the costs between ratepayers and  
11 shareholders, by including the cost of the transition severance program in rates, but  
12 requiring that any carrying charges associated with the deferral and amortization of these  
13 costs be the shareholders’ responsibility.

14  
15 The OCA position on this matter is consistent with the treatment of  
16 severance/restructuring costs of another era. In Docket No. 20000-ER-99-145,  
17 PacifiCorp “proposed to amortize over five years the one-time costs associated with its  
18 most recent early retirement program, placing in rate base the unamortized portion of the  
19 expenses.”<sup>3</sup> In that case, my recommendation was similar to my position in this case –  
20 ratepayers should be responsible to pay the annual expense amortization associated with  
21 the deferral while shareholders pay the carrying charges associated with the unamortized  
22 portion of the deferral. In its Order issued May 23, 2000, the Commission agreed with  
23 my position. It stated at paragraph 202(a) of its order:

24           Regarding the costs of PacifiCorp’s early retirement program, it is clear  
25           that not all of the costs are related to utility functions. Shareholders of  
26           PacifiCorp derive a benefit from the program, as do rate payers.  
27           Therefore, we accept the Consumer Advocate Staff proposal to reduce rate  
28           base and revenue requirements for this case to reflect a sharing of benefits  
29           between shareholders and ratepayers.

30  
31           The same sharing between ratepayers and shareholders that was accepted in an earlier  
32           rate case, for similar types of costs, is the OCA’s recommendation in this case.

---

<sup>3</sup> Direct Testimony of Denise Kay Parrish, Docket No. 20000-ER-99-145, page 11, lines 4 through 6.

1 **Q. DID ANY OTHER STATE ALSO ADOPT THE CONCEPT OF SHARING?**

2 A. Yes. In its deferral order on this issue, Order No. 30225 issued January 19, 2007, the  
3 Idaho Public Utilities Commission stated on page 3, "The Company shall not be entitled  
4 to any return, accrued interest or carrying charges associated with the deferred amounts."  
5

6 **Q. PLEASE EXPLAIN THE SERIES OF ADJUSTMENTS THAT YOU HAVE**  
7 **LABELED AS ROCKY MOUNTAIN POWER CORRECTIONS IN YOUR OCA**  
8 **SCHEDULES DKP-2 AND DKP-3.**

9 A. In addition to being summarized on my income statement and rate base schedules, these  
10 adjustments are also shown on OCA Schedule DKP-11. Throughout my review of the  
11 data in this case, Mr. McDougal has been forthright in providing a series of corrections  
12 that he and his colleagues found through their own review of this case and the  
13 development of the Utah rate case. These adjustments are found on OCA Schedule DKP-  
14 11, and I have incorporated them into the calculation of my revenue requirement.  
15

16 The first adjustment recognizes that the cost of benefits related to mining employees was  
17 included in the case twice: once through the cost of coal and once through the benefit cost  
18 forecast. This adjustment removes that double count by reducing employee costs  
19 allocated to Wyoming by \$431,883.  
20

21 The second adjustment recognizes that Rocky Mountain Power included one half of an  
22 adjustment but not the other half relative to the deferral of Powerdale decommissioning  
23 costs. Under the Company's original calculation, there was an increase in rate base  
24 relative to the deferral of the Powerdale decommissioning costs. It was the Company's  
25 intention to show no rate base impact for this item, and this correction zeros out the  
26 increase to rate base that had been originally included.  
27

28 The third adjustment is to recognize the tax credit that the State of Oregon allows on  
29 renewable energy property. This was inadvertently excluded in Rocky Mountain Power's  
30 filing. A total company figure of \$666,666 of tax credit is anticipated for the test year.  
31 When this amount is allocated it becomes an increase in tax expense – rather than the

1 decrease normally expected – because of the tax allocation factor that applies to  
2 Wyoming. As shown on Mr. McDougal’s Schedule SRM-2, page 10.10, the tax factor  
3 for income before taxes (the factor applied to the category in which this adjustment is  
4 made) is negative. This correction results in an increase in tax expense for Wyoming of  
5 about \$117,000.

6  
7 The fourth adjustment shown on OCA Schedule DKP-11 is similar to the third, in that  
8 they both relate to tax credits related to renewable energy. This fourth adjustment has  
9 two pieces: one related to the federal tax credit and one related to a Utah tax credit. The  
10 Utah tax credit is allocated on the same negative Wyoming factor described above, thus  
11 resulting in a tax increase. However, this is offset by the federal tax credit, which is  
12 allocated on the System Energy factor, which results in a decrease of taxes allocated to  
13 Wyoming. On a net basis, the adjustment reduces tax expense by about \$212,000.

14  
15 The fifth adjustment corrects the fact that demand-side management payments to Idaho  
16 irrigators were inadvertently included in the company’s purchased power expense that is  
17 allocated to all jurisdictions. These payments should be assigned on a situs basis directly  
18 to Idaho, and the adjustment makes this correction. Purchased power expense is reduced  
19 by about \$156,000 on a Wyoming allocated basis.

20  
21 The sixth adjustment corrects the computation of the level of fuel stock that is proposed  
22 to be included in rate base. This is a minor computational error that is proposed to be  
23 corrected here with a reduction to Wyoming rate base of about \$67,000.

24  
25 The last of these Rocky Mountain Power identified corrections is to recognize that the  
26 filed rate base includes the Company’s risk management system that has since been  
27 written-off. The adjustment removes the cost of the software from plant and removes the  
28 associated accumulated depreciation, for a net rate base reduction of about \$460,000.  
29 The other portion of the correction removes about \$39,000 of Wyoming allocated annual  
30 amortization expense.

31

1 **Q. PLEASE DESCRIBE YOUR ADJUSTMENT FOUND ON OCA SCHEDULE**  
2 **DKP-12.**

3 A. The adjustment to incremental transmission expense that I propose on this schedule is  
4 really an update to the adjustment proposed on Rocky Mountain Power on Mr.  
5 McDougal's SRM-2, page 4.12.1. In its original schedule, the Company proposed to  
6 include a series of additional costs related to additional employees that are anticipated to  
7 be hired to address additional transmission matters within the company. Also included  
8 were additional fees related to this additional transmission work.

9  
10 In my adjustment, I am acknowledging that not all of the transmission related employees  
11 that the Company plans to add have yet been hired. Based on the response to OCA Audit  
12 Data Request 13, as of November 1, 2007, only the Vice President - Planning, the  
13 Executive Administrator, and the Managing Director – Business Development have been  
14 hired. The response also indicates that these three positions were hired within the range  
15 of the cost estimate originally provided by Rocky Mountain Power.

16  
17 For the new employee positions that have not yet been filled, I allowed one-half of the  
18 originally forecast cost, anticipating that these employees may still be hired within the  
19 first half of the forecast test period. Since it is not currently known whether these costs  
20 will actually be incurred, a more aggressive position would have disallowed all of the  
21 costs of the positions not yet filled. However, I chose to take a more moderate position,  
22 since the OCA has supported the addition of new infrastructure, including new  
23 transmission requirements, and some of this new transmission investment is being made  
24 to support the growth in Wyoming load. My proposed adjustment removes about  
25 \$107,000 of Wyoming allocated transmission expense.

26  
27 **Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO PLANT HELD FOR FUTURE**  
28 **USE FOUND ON OCA SCHEDULE DKP-13.**

29 A. This adjustment removes about \$143,000 of Wyoming rate base and about \$1,500 of  
30 associated property taxes. This is a very small, rounding-error sized adjustment, but is  
31 consistent with adjustments made in prior cases to plant held for future use. This

1 adjustment applies the principle that plant held for future use for which there are no  
2 definitive plans, or for which there is no definitive time frame for the use of that property,  
3 should be excluded from rate base. That is the basis for the proposed OCA adjustment.  
4

5 **Q. WHAT IS THE PURPOSE OF SYNCHRONIZING THE INTEREST FOR**  
6 **COMPUTING INCOME TAXES, AS SHOWN ON OCA SCHEDULE DKP-14?**

7 A. Interest on long term debt is not shown as a line item on the operating income statement,  
8 but is instead recovered through the overall cost of capital. However, the level of interest  
9 plays a role in the computation of income taxes, as interest is deducted from operating  
10 income to arrive at taxable operating income, which is then used to compute income  
11 taxes related to the regulated operations of the utility. But, since it is often difficult to  
12 separate the debt that is used for regulated utility operations versus other activities of a  
13 utility, this adjustment has become a common part of computing a utility's revenue  
14 requirement. Essentially, the adjustment multiplies the weighted average cost of debt  
15 times the rate base to derive the interest that is reasonably necessary and useful to the  
16 utility's regulated operations. This amount is then deducted from operating income to  
17 derive taxable operating income.  
18

19 Since the company also synchronized the interest to its rate base, the adjustment shown is  
20 simply to recognize different inputs between Rocky Mountain Power's and the OCA's  
21 synchronizing calculation. Specifically, this adjustment recognizes the change that Mr.  
22 Freeman is proposing to the cost of debt and the reduced level of rate base recommended  
23 by the OCA compared to the Company's requested rate base. Overall, the adjustment  
24 reduces Wyoming allocated income taxes by about \$167,000.  
25

26 **Q. PLEASE DESCRIBE THE INFORMATION THAT IS FOUND ON OCA**  
27 **SCHEDULE DKP-15 REGARDING NET POWER COSTS.**

28 A. Mr. Freeman is the OCA witness on net power costs and these adjustments. However,  
29 for purposes of having a complete presentation of all of the OCA's adjustments, I have  
30 included this schedule that summarizes the adjustments to net power costs that he

1 recommends. The schedule shows that the OCA is recommending reductions to  
2 Wyoming allocated net power costs in the amount of \$8.4 million.

3  
4 **Q. WHAT ADJUSTMENT TO CASH WORKING CAPITAL IS FOUND ON OCA**  
5 **SCHEDULE DKP-17?**

6 A. The cash working capital in this case is based on a lead-lag study that was performed for  
7 an earlier case with one modification to reflect a change in the payment schedule of taxes.  
8 The OCA is not taking issue with the use of this study. However, as part of the  
9 calculation, the computed lag is multiplied by the daily average level of operations and  
10 maintenance expense. Given the above described adjustments to various expenses, the  
11 OCA's average daily expense level is different than that of Rocky Mountain Power. This  
12 adjustment reflects that difference in the cash working capital amount. The result is that  
13 the OCA adjustment reduces rate base by about \$1.5 million.

14  
15 **Q. OCA SCHEDULE DKP-18 LISTS THREE ADJUSTMENTS TO RATE BASE.**  
16 **PLEASE DESCRIBE EACH OF THESE ITEMS.**

17 A. The first of the listed adjustments is to the Cove Hydro Decommissioning adjustment  
18 reflected in Rocky Mountain Power's filing at Schedule SRM-2, page 8.3. In its  
19 adjustment, the Company removed from rate base the cost of the Cove plant which was  
20 decommissioned in the fall of 2006. However, it did not make the corresponding  
21 adjustment to also remove the associated accumulated depreciation from rate base. The  
22 OCA adjustment does this. This OCA adjustment falls into the philosophically correct  
23 category but is so minor as to be rounding error, in that it increases Wyoming rate base  
24 by \$21,000.

25  
26 The second of these adjustments relates to the Upper Beaver Hydro Facilities Sale and is  
27 very similar in nature to the Cove Hydro adjustment. At Schedule SRM-2, page 8.4,  
28 Rocky Mountain Power includes an adjustment to rate base to remove the Upper Beaver  
29 hydro facilities that are being purchased by Beaver City. While the Company's  
30 adjustment reflects changes to plant in service, it does not reflect the corresponding

1 change to accumulated depreciation. The OCA adjustment in this case is slightly larger,  
2 in that it increases Wyoming rate base by about \$246,000.

3  
4 The third of these adjustments is to the Cottonwood Coal Lease. As described on Mr.  
5 McDougal's Schedule SRM-2, page 8.8, Rocky Mountain Power included about \$1.2  
6 million in Wyoming's rate base to reflect its anticipated participation in an auction to  
7 lease the Cottonwood coal reserves from the Utah Trust Lands Administration. The \$1.2  
8 million (or \$7 million on a total company basis) was the amount that it anticipated paying  
9 in 2007 as part of the auction process. However, it has come to my attention that Rocky  
10 Mountain Power did not win that bid, and thus the inclusion of this cost in rate base  
11 should be eliminated. The OCA adjustment removes this amount from rate base,  
12 negating the amount that had been included in the original filing.

13  
14 **Q. IS THERE ONE ADDITIONAL COMPUTATIONAL ITEM THAT YOU WISH**  
15 **TO EXPLAIN AT THIS TIME?**

16 **A.** Yes. As shown on OCA Schedule DKP-1, there is a slight difference between the gross  
17 revenue tax conversion factors utilized by Rocky Mountain Power and the OCA. This  
18 difference is minor and is primarily a difference in form rather than content. The OCA  
19 has increased the gross revenue tax factor to recognize that as revenues change, not only  
20 do taxes change but so do expected uncollected revenues. This is part of the normal  
21 computation in computing rates in rate cases. Rocky Mountain Power makes a similar  
22 adjustment for additional expected uncollectibles, but makes it as a specific adjustment to  
23 the income statement rather than within the conversion factor. All other things being  
24 equal, the end results of the OCA and the Rocky Mountain Power computations are  
25 intended to be the same. The uncollectible percentage that is recognized in both  
26 computations is 0.155%.

27  
28 **Q. ARE THERE OTHER ADJUSTMENTS THAT YOU BELIEVE ARE**  
29 **APPROPRIATE FOR THIS CASE THAT YOU HAVE NOT QUANTIFIED IN**  
30 **YOUR SCHEDULES?**

1 A. Yes. The interjurisdictional cost allocation methodology employed by Rocky Mountain  
2 Power, and approved by this Commission, includes an embedded cost differential  
3 adjustment. As described in the Stipulation and Agreement in Docket No. 20000-EI-02-  
4 183, the embedded cost differential is has two parts: one for Company Owned Hydro and  
5 one for Mid-Columbia contracts. But, in both instances, the differential between the  
6 annual hydro embedded costs and the embedded costs for all other power resources is  
7 computed and then allocated to give additional benefit of the hydro resources to the  
8 Pacific Power states.

9  
10 None of my adjustments reflect any changes to this embedded cost differential. Yet, I  
11 anticipate that such changes to the allocation and the differential may be necessary if the  
12 Commission adopts some of the adjustments being proposed in this case, particularly  
13 some of the adjustments to net power costs.

14  
15 I suggest that the Commission find a procedurally correct way, preserving the rights of all  
16 parties, to incorporate these conforming adjustments into its decision in this case, once it  
17 has had the opportunity to determine which of the recommended adjustments that it will  
18 adopt for purposes of setting the rates in this case. This might be done as part of a  
19 compliance filing that Rocky Mountain Power would be directed to make in response to  
20 the deliberations and order. For example, the Commission could direct Rocky Mountain  
21 Power to provide a compliance exhibit to the Commission and all parties in response to  
22 the Commission's deliberations on the issues. This would assure that all of the  
23 adjustments and computations were synchronized based on the PacifiCorp computer  
24 program for computing the revenue requirements with each element tied to the next. A  
25 similar process has been used in the past with reasonable success. This is really not much  
26 different than asking the Company to file conforming tariffs in response to Commission  
27 deliberations except that an additional item would be provided that showed the final  
28 revenue requirement computation resulting from deliberations.

29  
30 **Q. DO YOU ANTICIPATE THAT THE CONFORMING ADJUSTMENTS TO**  
31 **WHICH YOU REFER WILL BE LARGE?**

1 A. No, I do not. However, with a case of this size and complexity, and given the number of  
2 contested items contained even just within the OCA's testimony, the Commission staff  
3 should not be expected to perform this computation – especially when there is a computer  
4 model programmed and available to make the ultimate computation on an expedient  
5 basis. This process would also allow each of the parties a brief opportunity to review the  
6 results for accuracy prior to their filing with the Commission.

7  
8 **Q. MS. PARRISH, DO YOU HAVE ANY ADDITIONAL COMMENTS THAT YOU**  
9 **WISH TO MAKE REGARDING THE INTERJURISDICTIONAL**  
10 **ALLOCATIONS USED IN THIS CASE?**

11 A. Yes. As the Commission is well aware, I have over the past year expressed, in various  
12 forums, my dissatisfaction with the current allocation process. I am not particularly  
13 concerned about the allocation of existing resources and common expenses, although the  
14 current process is far from theoretically perfect. My biggest concern is how the current  
15 allocation agreement is impacting the decision making process of determining future  
16 resources. I strongly believe that changes must be made and that we are seeing the start  
17 of those changes with the reallocation of the renewable energy credit revenues proposed  
18 by Rocky Mountain Power in the Utah rate case and proposed by the OCA in this rate  
19 case.

20  
21 As much as I want the discussions of necessary changes to cost allocations (and resource  
22 planning) to occur – and even to have occurred yesterday – I have chosen not to force the  
23 issue in this case. I think there were several opportunities to reopen the entirety of the  
24 Multi-State Process in this case, and as much as I considered doing so, in the end I  
25 concluded that this was not the correct forum. That conclusion was reached partly on the  
26 discussions that have begun to occur with the Commission in other forums on the  
27 relationship between resource planning and cost allocations. I am banking on a  
28 continuation of those discussions in the near future.

29  
30 Cost allocation decisions, and their impact on existing and future resources, have a direct  
31 impact on rates in this case and future cases. It is critical that the Commission and the

1 parties recognize in this case the importance of these allocations, even if specific  
2 adjustments and formulistic changes are not proposed herein. We ask that the  
3 Commission do what is necessary and appropriate to keep the discussions on this  
4 essential issue alive.

5  
6 **Q. ARE THERE ANY FOLLOW-UP ISSUES FROM THE LAST ROCKY**  
7 **MOUNTAIN POWER RATE DOCKET THAT ARE IMPORTANT TO DISCUSS**  
8 **IN THIS CASE?**

9 A. Yes. As part of the Stipulation and Agreement in the prior rate case (Docket No. 20000-  
10 230-ER-05) that was approved by the Commission in an Order issued March 24, 2006,  
11 the Company agreed to

12 ...implement an AFOR tracking mechanism that results from the  
13 collaborative process for test purposes only and will share information  
14 with the Parties regarding the AFOR tracker as that information is  
15 developed, subject to reasonable requirements for the protection of  
16 confidential information.  
17

18 On or about August 31, 2007, Rocky Mountain Power shared with the parties their first  
19 AFOR Tracking Results. These results show that the overall Wyoming expenses that  
20 would have resulted from the AFOR being tracked were about \$11 million less than the  
21 December 2006 actual company expenses. It also showed the rate base computed under  
22 the AFOR tracking mechanism would have been about \$32 million less than the result  
23 shown for December 2006 actual financials.

24  
25 The discussions of implementing an AFOR have not received great support from many of  
26 the parties in the prior rate case, and thus have been put on the back burner for now.  
27 However, it was abundantly clear in prior discussions about alternative forms of  
28 regulation that one large hurdle to adoption was the lack of real life experience of how  
29 one would work. It was this desire for additional information that drove the AFOR  
30 tracking provision in the prior stipulation. We now have one partial year of experience.  
31 It would be desirable to have more real PacifiCorp experience to study if AFOR  
32 discussions were to be moved back to the front burner. For this reason, the OCA asks the  
33 Commission to direct Rocky Mountain Power to continue to track the selected AFOR

1 program for informational purposes for the next few years. We are not asking for any  
2 additional mandated discussions at this time, nor are we asking for any implementation of  
3 previously discussed programs. We are simply asking that additional data continue to be  
4 gathered, based on the results of the prior discussions.

5  
6 **Q. DOES THIS CONCLUDE YOUR DIRECT, PRE-FILED TESTIMONY IN THIS**  
7 **PROCEEDING?**

8 **A.** Yes, it does.