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

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

QUALIFICATIONS

Q. What is your current position at Rocky Mountain Power (the "Company") and your employment history?

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

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

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

Q. What is your educational background?

A. I received a Master of Accountancy from Brigham Young University with an emphasis in Management Advisory Services in 1983 and a Bachelor of Science degree in Accounting from Brigham Young University in 1982. In addition to my formal education, I have also attended various educational, professional and electric industry-related seminars.

Q. Have you testified in previous proceedings?

A. Yes. I have provided testimony before the Washington Utilities and Transportation Commission, the California Public Utilities Commission, the Idaho Public Utilities Commission, the Wyoming Public Service Commission and the Utah State Tax Commission.

PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. My direct testimony addresses the calculation and need for the $161.2 million increase requested in the Company's application. In support of this calculation, I address the following issues:

- A summary of the calculation of the $161.2 million requested rate increase.
- The need for the forecast test period which is proposed in this case (twelve months ending June 30, 2009 – the "Test Period").
- Forecasted results of operations for the Test Period demonstrating that the Company will earn an overall return on equity ("ROE") in Utah of 5.8 percent.
- Results of Operations for the "Base Period" (twelve months ended June 30, 2007 with known and measurable changes through June 30, 2008) and the "Mid Period" (twelve months ending June 30, 2008).

REQUIRED RATE INCREASE

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

A. Presented as an exhibit to my testimony is the Company's Utah Results of Operations for the twelve months ending June 30, 2009 labeled as Exhibit RMP___(SRM-1). My testimony presents evidence that, based on its results of operations for this test period, at current rate levels Rocky Mountain Power will earn an overall ROE in Utah of 5.8 percent for the twelve-months ending June 30, 2009. This return is less than the 10.25 percent ROE included in the stipulation in Docket No. 06-035-21 and is less than the 10.75 percent return recommended in Dr. Samuel C. Hadaway's testimony to provide a fair and equitable return for the Company's shareholders. An overall price increase of $183.4 million is required to produce the 10.75 percent ROE requested by the Company in this proceeding.

Q. What allocation methodology was used in the calculation of the Utah Results of Operations?

A. The Company has used the Revised Protocol allocation method, as approved by the Commission in Docket No. 02-035-04 to calculate Utah's Results of Operations and the associated ROE. The use of Revised Protocol resulted in a Utah ROE of 5.8 percent and a required rate increase of $183.4 million to earn a 10.75 percent ROE.

Q. Is the Company requesting the full $183.4 million required to earn a 10.75 percent ROE?

A. No. The Company has reflected the Rate Mitigation Cap as stipulated and approved by the Utah PSC in Docket No. 02-035-04. The stipulation states:

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

For purposes of this case, the Rate Mitigation Cap is computed by taking nine months of the 101.25 percent cap, and three months of the 101.00 percent cap to align the mitigation cap with the test period. This adjustment reduces the rate request by $22.2 million to $161.2 million as shown in my Exhibit RMP___(SRM-1) on page 1.0 of Tab 1 Summary.

Q. Please describe some of the key areas where the Company has experienced cost increases that support the $161.2 million requested price increase.

A. Since the 2006 Utah general rate case, the Company has incurred cost increases to service its customers in two main areas: new plant investment and net power costs.

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

- The Company continues to make significant investment to serve its customers. Utah allocated net rate base has increased by over $835 million from the September 2007 test period amount included in the Company's last Utah rate case filing. Significant new generating plant investments which were either not included or not fully included in the prior rate case include the Blundell bottoming cycle, Huntington 2 scrubber, Leaning Juniper Wind plant, Marengo Wind plant, Marengo II Wind Expansion, Lake Side plant, Cholla 4 environmental upgrade, Glenrock Wind plant, Seven Mile Hill Wind plant and the Goodnoe Hills Wind plant as described in the direct testimony of A. Robert Lasich.
- The Company is continuing to see significant increases in Transmission and Distribution plant in service. This case includes $344 million in transmission plant additions and $588 million in distribution plant additions between July 1, 2007 and June 30, 2009. Over half of the distribution plant additions are in the state of Utah.
- Net power costs, as addressed by Mr. Mark T. Widmer, are projected to increase. Net power costs are projected to increase $279 million on a total company basis as compared to the September 2007 projection included in the Company's last Utah rate case.

Q. How are the outstanding rate-related Utah dockets treated in this rate case?

A. The Company has four unresolved rate-related dockets filed with the Utah Commission: 1) Docket No. 07-035-04 requesting deferral of MEHC transition costs; 2) Docket No. 06-035-163 requesting deferral of the Grid West Loan; 3)

Docket No. 07-035-14 requesting an accounting order on the Powerdale Hydro plant; and 4) Docket No. 07-035-13 requesting authority to change depreciation rates effective January 1, 2008. The impact of each of these open dockets is included in this rate case based on the Company's filed position. The Company will let parties to the rate case know the impact on the rate case of the Commission orders after final orders are received. The impact of the final orders will be included in the Company's rebuttal filing in this case.

RATE CASE FORECAST TEST PERIOD

Q. Please provide an overview of your testimony on the test period in this case.

A. Consistent with Utah statutes, the Company has proposed a forecast test year in this case that begins on July 1, 2008 and ends on June 30, 2009. The purpose of this portion of my testimony is to explain why this test period best reflects the conditions the Company expects to experience in the rate effective period. In so doing, I will discuss how matching principles and regulatory lag affect the choice of test year and review the process of developing the Company's test year forecast and explain why the result is reasonable.

Matching Principle

Q. When will a rate change likely become effective in this case?

A. Given their complexity, it is typical for orders in general rate cases to become effective near the end of the statutory 240-day period provided under section 54-7-12(3) of the Utah utility code. Thus, the commencement of the rate-effective period (August 2008) and the commencement of the test period (July 2008) will closely match each other in this case.

Q. Why is it important that the test period and the rate effective period closely match each other?

A. One of the important underlying principles of fair utility rate-making is to match capital investment, prudent expenses and revenues with the conditions that the utility will actually experience when the new rates are in effect. The capital investment, prudent expenses and revenues that are used to determine the utility revenue requirement come from a "test period." The time period when the new rates are in effect is referred to as the "rate-effective period." To the extent possible, the rate-effective period and the test period should closely match each other. In other words, the new rates should take effect on the commencement of the test period. Traditional historical test periods will never match the rate-effective period and, as I discuss later in my testimony, will result in the utility chronically under-recovering its cost of service when the utility is experiencing rapid expansion and rate base growth. The use of a forecast test period is necessary and essential to the Company if it is to have a reasonable opportunity to earn its cost of capital.

A rate base, rate of return regulated utility like Rocky Mountain Power must be given a reasonable opportunity to earn its cost of capital. In fact, by creating a statutory mandate that the type of forecast test period proposed by the Company in this case be given serious consideration, the Utah Legislature has expressed its clear intent that Utah utilities will be given a reasonable opportunity to earn their authorized return.

Q. Why is the Company advocating the use of a forecast test period in this proceeding?

A. As discussed in both Mr. A. Richard Walje's and Dr. G. Michael Rife's testimony, the Company has experienced and continues experiencing unprecedented load growth and we expect this trend to continue into the future. The Company expects a significant amount of new load in the Utah service territory. In addition, the Company foresees continued load growth in the other states that it serves. The need to serve growing load requires the Company to acquire new generating resources; the costs and benefits of some new resources are reflected in rates for the first time in this case. This filing includes the full impact of the Lake Side facility which adds 548 MW of generating capacity, as well as various new wind projects adding over 500 MW of capacity. Significant new investments in transmission and distribution systems are required to integrate these new resources and ensure continued reliability. Net power costs continue to escalate as a result of increasing fuel costs, purchased power and load growth. Only a forecast test period can fully capture the rate-making impacts of growing customer load, the capital investment required to serve it, and the operation and maintenance costs required to maintain system safety and reliability. The use of a forecast test period is the only proper method to reflect for rate-setting purposes the costs the Company will incur in the rate-effective period to provide the level of service required by its customers.

Regulatory Lag

Q. Please explain what is meant by the term "Regulatory Lag."

A. The phrase "regulatory lag" refers to the time difference between when costs are measured for the Company's revenue requirement and when costs are actually incurred in providing service to its customers. More than anything else, regulatory lag is the result of the rate-making process, test period selection, and the time that it takes to set customer rates. If new rates do not reflect the costs being incurred at the time the rates are in effect, regulatory lag is created.

Q. Please explain Exhibit RMP___(SRM-3).

A. Exhibit RMP___(SRM-3) is a graphical representation of the problem with regulatory lag. This Exhibit compares a historical base period, July 1, 2006 through June 30, 2007, and the forecast test period proposed in this case, July 1, 2008 through June 30, 2009, to the rate-effective period beginning in mid-August, 2008. This exhibit highlights the mismatch in investments, operating costs, revenues and loads between the two example test periods and the rate-effective period. Exhibit RMP___(SRM-3) shows that regulatory lag ranges from 19.5 months based on the purely historical base period, to 13.5 months based on the mid period, and down to less than two months in the forecast period where the revenues and loads are matched with the forecast cost to serve.

Q. Why is regulatory lag a problem?

A. Regulatory lag is a serious problem when a utility is only authorized to charge rates based on historical (backward-looking) costs while it incurs a steady upward trend in investments and expenses for the foreseeable future. As Exhibit

RMP___(SRM-3) shows, there is an obvious disparity between costs in the historic base period and the higher costs that the Company will incur in the rate-effective period. The Company is in a period of increasing energy-related costs that are coupled with substantial new investments being made by the Company to serve customer loads. As a result, basing rates on a test period that doesn't reflect the costs to serve customers during the rate-effective period effectively denies the Company a reasonable opportunity to earn the return authorized by the Commission and recover the costs it incurs in serving customers.

Q. If you receive rate increases based on forecasted costs, how can the Commission be assured that this additional funding will be used for the benefit of customers?

A. During this period of rapid system growth, the Company will have an ongoing need to continue a high level of investment in the system in order to maintain and increase service reliability. The Company is committed to filing Utah Results of Operations semi-annually with the Commission, DPU and CCS, that give parties a chance to review the Company's earnings to verify that the Company is not over-earning its allowed rate of return.

Q. Would a test year other than the Company's forecast test year adequately capture the costs the Company will experience in servings its customers during the rate effective period?

A. No. Other test year options simply do not provide the Company with a reasonable opportunity to fully recover its cost of service. I have previously described the types of expected cost increases that necessitate the use of a forecast test year. It is important to recognize two additional facts about the Company's test year proposal. First, capital additions between July 1, 2007 and June 30, 2008 will not be fully included in revenue requirement unless a forecast test period is used, despite the fact that the projects are scheduled to be completed prior to the anticipated order in this case. It is anticipated that the company will have almost $1.9 billion of capital additions between July 1, 2007 and June 30, 2008 including the Lake Side Power Plant, Blundell Bottoming Cycle, Cholla 4 environmental upgrade, and the Marengo and Goodnoe Hills wind projects. Second, the Company expects an additional $1.4 billion in plant additions during the test year (July 1, 2008 through June 30, 2009). This includes three additional wind projects at a capital cost of approximately $550 million adding an additional 268 MW of capacity. These additions are included in the test period based on the number of months they will be in-service, consistent with their inclusion in the net power cost study.

Development of Test Period Forecast

Q. Is Rocky Mountain Power’s forecast for its proposed test period reasonable?

A. Yes. Rocky Mountain Power’s forecast is: 1) grounded in actual data; 2) reflective of realistic and systematic cost and revenue projections; 3) developed and supported at the operating level; 4) consistent with actual performance; and 5) readily accessible for external review and analysis.

Q. Please explain how Rocky Mountain Power's test period forecast is grounded in actual data.

A. The test period was forecasted using the historical twelve months ending June 30, 2007 ("Base Period") as the starting point. From that Base Period, each of the revenue requirement components was normalized or adjusted to remove any non-recurring items. The forecast test period is then further adjusted to recognize known and measurable events, to include previously ordered Commission adjustments and to properly match projections of revenues, expenses and investment conditions in the rate-effective period. The specific forecasting methods used for each revenue requirement component will be more fully discussed later in my testimony.

Q. Please describe the process used to project test period costs and revenues.

A. Retail revenues were forecasted by applying the current Commission-approved tariff rates to the test period load forecasts. The testimony of Dr. Rife describes the comprehensive approach used to forecast loads for this case. Wholesale sales forecasts (as well as all other components of net power costs) were developed using the Generation & Regulation Initiative Decision ("GRID") model, which has been used extensively in prior general rate cases and other regulatory proceedings in Utah. Normalized base-year operations and maintenance expenses, excluding net power costs, ("O&M") were split into labor and non-labor components. Non-labor costs were escalated using well-established, nationally recognized inflation indices provided by Global Insight. The escalated amounts were compared to Company budgets, and if any significant differences existed, the escalated amounts were adjusted to reflect expected test period conditions. Labor costs were adjusted for expected increases through the end of the test period. These forecasting procedures are explained in greater detail later in my testimony and exhibits, where I explain the development of the Utah revenue requirement.

Q. How does the forecast capture costs that are projected to increase significantly different than the cost indices?

A. Cost indices are effective for projecting the future only to the extent that all future cost components are included in the Base Period. Since the Company will be placing many new generating resources into service and increasing O&M expenses above historic levels, a forecast based entirely on indexed inflation changes would not capture all conditions expected during the rate-effective period. The Company does a high level comparison of the budget and the forecast test period to capture additional adjustments necessary in the forecast test period.

Q. Does the Company have a rigorous budgeting process that is capable of supporting a forecast test period?

A. Yes. The Company's operating and capital budgets are reviewed and approved by the Company's senior management and the management of its parent company, MidAmerican Energy Holdings Company ("MEHC").

Q. Please summarize the budgeting process that supports the test period forecast.

A. Because new resource additions are a significant component of this case, my explanation will focus on the capital budget, although operating budgets follow a similar procedure. Initially, a long-term view of the Company's projected capital expenditures is developed by managers at the operating level. This long-term view is refined annually during the budget process to reflect the current needs of customers and the operating plans of the Company. Capital investment is then allocated into discrete investment categories, not specific projects.

Q. Have the cost assumptions underlying the test period forecast been reviewed and supported by the Company managers who are responsible for actually constructing capital projects and operating and maintaining the system?

A. Yes, the Company's managers are the source of the costs that are included in the forecast and are prepared to support these forecasts.

Q. What is the process for validating test period forecasts at the operating level?

A. To the extent budget data is relied on in developing the rate case forecast, it is developed and reviewed at the operating level. The preparation of the test period forecast follows a similar approach to the budgeting process. During the preparation of the rate case, meetings are held with operating managers to review labor forecasts, escalation of non-labor costs, forecast capital additions, and all other components of test period costs. The overall test period forecast is not finalized until all of the costs have been approved at the operating level. This operating level review provides additional assurance that the test period amounts are in line with the Company's business plan.

The Company has developed a well-documented forecast test period that reflects the costs that the Company will incur in serving its customers when new rates go into effect. The forecast properly matches all of the components of the revenue requirement and is appropriate for setting rates in this case.

Rate Effective Period

Q. Do you believe the appropriate test year should be based on the best evidence of the conditions in the rate-effective period?

A. Yes. The Commission's statutory charge is to select the test period that, in the exercise of its judgment based on the evidence, will best reflect the conditions in the rate effective period. In its analysis of what is fair for the Company and its customers, the Commission should select the test year that reflects the unique costs and circumstances of the rate effective period.

Q. What evidence can you offer the Commission that the test year proposed by the Company in this case, the twelve months ending June 30, 2009, best reflects the conditions expected in the rate effective period?

A. It may be helpful to begin by examining the alternatives for selecting a test year that matches the rate effective period. A completely historic test year is not an option available under current statute. A historic test year with known and measurable adjustments creates serious mismatches between revenues and expenses within the test period. Likewise, a historic test period with known and measurable adjustments and a mid-period forecast offer no link to the rate effective period and do not adequately reflect the anticipated cost levels in the rate effective period. Only a forecast that most closely matches the rate effective period will adequately reflect the costs and circumstances that the Company will experience during that period.

Q. What is the advantage of the test period proposed by the Company?

A. The Company's proposed test year has the advantage of close proximity to the expected rate effective period on an actual calendar basis. The Company's test year forecast reflects the conditions that the Company expects to experience when the new rates are in effect. The use of any other test period requires the assumption that the revenues and expenses developed for the test year will not change for an extended period of time until the rates become effective. Since this assumed stability creates a greater risk of mismatch with the rate effective period, the Company's forecast period is the most logical choice because it most closely matches the rate effective period.

Consistent With Actual Performance

Q. How have previous Utah test year forecasts compared to actual results for the same period?

A. In Docket No. 06-035-21 the Company filed a forecast test period for the twelve months ending September 2007. A comparison of the forecast test period with actual results shows that the Company's forecast was conservative in almost all areas. While the forecast test period did not exactly match actual results for the rate effective period it was much closer than the Base-period or Mid-Period amounts, and best reflected the conditions in the rate effective period.

An example is electric plant in service, one of the main cost drivers in Docket No 06-035-21. The Company forecasted an average electric plant in service balance of $15.6 billion, actual results were $15.7 billion. The historical amount on Docket No. 06-035-21 was $13.8 billion and Mid-Period amount was $14.6 billion. Also, the forecast total net rate base and the actual net rate base for September 2007 were both $8.3 billion compared to the base period of $7.2

billion.

Q. Does the manner in which the Company has calculated its forecast capital additions constitute a prepayment?

A. No. The Company has used the 13-month average method of calculating rate base in this case. Under this approach, asset additions are not included in rate base until the month in which they are actually placed in service. For example, the Glenrock Wind plant will be completed in December 2008. Therefore, for the forecast test year July 1, 2008 to June 30, 2009, there will be no Glenrock Wind costs in rate base during the months of June 2008 through November 2008. The investment will not be added until December 2008. Since the new rates will be based on the Company's 13-month average rate base, rates only reflect a partial recovery of the new plant investment. In other words, the revenue requirement will reflect nothing for the Glenrock Wind plant until December 2008 and will reflect the full cost of the new plant only them from December 2008 through June 2009. This is consistent with the net power cost benefits of the plant. The net power cost study includes the plant for these same months, and the customers are getting the benefit of the zero net power cost resource for these months.

Q. Do you believe that the approach used by the Company to forecast test year rate base is conservative and beneficial to customers?

A. Yes. During the first year the new rates are in effect, customers will bear the cost of new assets only for the period of time they are projected to be in service during that period. After the first year, these assets will be fully in service, but cost recovery will continue to be based on their partial inclusion in the test year.

Customers will continue to pay less than a full annual return on this investment until new tariff prices are established in a new rate case.

Q. Based on the preceding discussion is it your conclusion that the Company's forecast capital additions are consistent with proper ratemaking principles?

A. Yes. Under the Company's forecasting approach, customers bear only the cost of new plant for the period it is projected to serve them.

Q. Why is it important that the Company's forecast has been documented?

A. I believe that the care that the Company has taken to document and explain its forecast along with its willingness to openly and voluntarily share information is the clearest indication that its approach to forecasting is reasonable. I have explained that the Company has applied a rational, systematic and comprehensive approach to the preparation of its forecasted test year revenue requirement. Based on the factors I have previously described, I believe that the forecast test year revenue requirement developed and proposed by the Company is fair and reasonable and is most likely to match the conditions in the rate effective period.

Q. Is it possible to devise a test period that is free from some element of prediction?

A. Of course not. The reality is that the Commission is charged with setting rates for a future, not a historic, period and that inevitably involves a certain amount of informed projections of the future for any test period that is used. In prior years, historic test periods with no out-of-period adjustments have been used in an effort to remove Company judgment and discretion from the calculation of the revenue requirement. However, given the dynamic nature of the world in general and the electric industry in particular, it is unlikely that a pure historic test year will "best reflect" the conditions in the rate-effective period at the present time; and, in fact, an unadjusted historic test year is not even an option that is available to the Commission under the current statute. All of the test year options require the Company to exercise informed judgment about how to best project future data or adjust historical data to reflect conditions in the rate effective period.

Q. Do you have any other general observations about the use of a forecast test year?

A. The Commission is required by statute to choose the test period that best reflects the conditions in the rate effective period. The Utah Legislature has explicitly made a forecast test year option available to the Commission. The Company now finds itself in a period where both capital and O&M costs are increasing significantly to meet growing customer demand for electricity and rising cost pressures. The Commission should require customers to pay a price today that matches the cost to serve that customer today. Any business that charges prices today that reflect two year old costs will always under-perform. I do not believe that the legislature would have authorized the use of a forecast test year if it were not convinced that this option might be necessary to best reflect the conditions in the rate-effective period. In fact, I believe that the Company's current circumstances are a perfect example of the need for a forecast test year that was anticipated by the Legislature.

Test Period Summary

Q. Please summarize your conclusions about the appropriate test year to be used by the Company in this proceeding.

A. The test period used in this proceeding must satisfy two objectives. First, it must best reflect the conditions in the rate-effective period as required by statute, and secondly it must provide the Company with a reasonable chance of fully recovering the escalating costs of serving the growing electrical needs of its Utah customers. There is simply no way that a historical test year, even with selected adjustments, can recover the increased net power costs, O&M expense and capital required to serve this growing load. These costs are only exacerbated by the fact that the load is growing faster on peak than it is overall. The fact is that in order to have an opportunity to recover its full cost of service and earn its authorized return on equity, the Company must employ a test year that is properly matched with the rate-effective period. My testimony has demonstrated that the Company has applied a rational, systematic, and comprehensive approach in forecasting its test year revenue requirement. I have explained that the resulting revenues and costs are fair and reasonable and are most likely to match the conditions in the rate effective period. Therefore, the Commission should approve for purposes of this proceeding, a forecast test year beginning July 1, 2008 and ending June 30, 2009.

Utah Test Period Results of Operations

Q. Please explain the process used to calculate the results of operations for the Test Period in this application.

A. The Test Period in this case was developed in four steps.

First, the Company started with the historical results of operations for the twelve months ended June 30, 2007 (“Actual Period”).

Second, the actual period was normalized to remove any non-recurring items, unusual weather or hydro conditions. Known and measurable adjustments through June 30, 2008 were then added to come up with the “Base Period”, a historical rate case with known and measurable adjustments. These normalized Results of Operations are summarized as the “Base Period” in Exhibit RMP___(SRM-2).

Third, the “Mid Period” was developed, which represents forecasted results of operations for the twelve months ending June 30, 2008. The Mid Period utilized the load forecast as discussed in the testimony of Dr. Rife. Retail revenues were forecasted by applying the current tariffs to the Mid Period load forecasts. Net power costs, which were developed using the Generation & Regulation Initiative Decision (“GRID”) model, utilized the same load forecast.

The normalized Base Period O&M expenses were split between labor related and non-labor costs. The non-labor costs were escalated by utilizing functional specific (i.e. production, transmission, distribution, etc.) inflation indices prepared by Global Insight’s Utility Cost of Service. These results were then compared to the budget for the corresponding period. In limited areas where the budget differed significantly from the escalated amounts, the known cost drivers were identified and the differences added to the escalated amounts to better reflect the expected Mid Period operating conditions.

Labor costs were adjusted to capture wage and employee benefit increases through the end of the Mid Period. The labor and non-labor costs were then combined.

The fourth and final step was to segue from the Mid Period to the Test Period Results of Operations. The same process used to walk the Base Period to the Mid Period was employed. The load forecast for the twelve-months ending June 30, 2009 was the basis for developing the Revised Protocol allocation factors, the general business revenues and the net power costs. Non-labor O&M was escalated to capture another year of inflation and labor related expenditures were adjusted for increases to wage and benefits. Electric plant in service was developed from the Company's capital budgets based on project spend and completion dates.

The development of the Test Period results is summarized in six tabs in Exhibit RMP___(SRM-1), the "Report". Revenues are summarized in Tab 3 – Revenue Summary. The O&M forecast is summarized in Tab 4 – O&M Summary. The net power cost forecast was produced using the GRID model and is summarized under Tab 5 – Net Power Cost Summary. Annual depreciation expense was developed by applying the Company's composite functional depreciation rates based on the Company's August 31, 2007 application for authority to change depreciation rates effective January 1, 2008 to the forecasted plant balances as summarized in Tab 6 – Depreciation and Amortization Summary. Tab 7 is the Tax Summary. Tab 8 contains the Rate Base Summary.

There are two additional tabs; Tab 9 – Rolled-In Methodology restates the results summarized in Tab 2 utilizing the Rolled-In allocation in compliance with the Revised Protocol approval order. Tab 10 – Allocation Factors, shows the derivation of the Revised Protocol Allocation Method ("Revised Protocol") factors.

I will discuss the calculation of each of these components in more detail later in my testimony.

Q. Please explain how inflation escalators were used in your forecast.

A. Inflation indices were applied to most of the O&M non-labor costs. Inflation increases the Company's cost of goods necessary to provide service. After non-labor costs were isolated from labor costs, utility index inflation indices were applied to escalate the Base Period costs other than net power costs to the Test Period. The advantage of using inflation indices to produce a forecast is that the resulting calculations are easily understood and readily verifiable. However, a forecast based solely on applying inflation indices to a historic Base Period assumes that all future cost increases will track the general rate of inflation.

Q. Are there additional areas where future cost increases will not track the general rate of inflation?

A. Yes. In order to rely solely on inflation indices, all the cost components that the Company will incur in the Test Period need to be in the Base Period. For example, in order to serve growing system loads the Company will be making substantial capital investments over the historic levels in the Base Period. Because of the new generation resources and growth in specific cost categories, a forecast test period based entirely on indexed inflation changes would not capture the new investments or the associated operating costs in the rate-effective period.

Q. Who provides the utility indices used by the Company to forecast O&M costs?

A. The indices are developed by Global Insight. The Company has relied on Global Insight's indices in forecast test period rate cases in Oregon, California, Wyoming and Utah. The Company also used these factors in the future test period (ending September 30, 2007) proposed in the last Utah rate case.

Q. Why does the Company use Global Insight's inflation indices?

A. Global Insight provides a detailed assessment of the electric market and is a utility cost index with the most granular level of detail available. There are many high-level indices that are both historical and forward-looking. One of the most recognized and generally accepted indices is the Consumer Price Index ("CPI"). CPI contains a select basket of goods which include food, housing, utility costs, apparel, transportation, recreation, education, and other goods and services. In contrast, Global Insight's index is based on electric utility costs according to the Uniform System of Accounts defined by the Federal Energy Regulatory Commission ("FERC") for major electric utilities and major natural gas pipeline companies. The Global Insight study used to prepare this filing was Global Insight's Utility Costs of Service, release dated October 8, 2007. A summary of these indices is included on page 4.16 in Exhibit RMP___(SRM-1).

Q. At what level of detail are Global Insight's indices prepared?

A. Global Insight's indices are prepared at the FERC functional subcategory level and are denoted with their corresponding FERC account number. The individual FERC account level indices are then combined into broader indices representing operation, maintenance, or total operation and maintenance expenses.

Q. Is labor expense included in these Global Insight cost indexes?

A. No. Global Insight provides an O&M cost index forecast excluding labor expense (materials and services only). These factors are denoted by the "MS" at the end of each factor on page 4.16. The Company uses these non-labor factors to escalate the non-labor O&M costs, and relies on Company projections and union contracts to escalate labor costs.

Q. How has the Company addressed areas where cost increases were different than inflation?

A. After O&M was calculated, it was compared to the Company's budget. In areas where there were large discrepancies, the appropriate business unit within the Company was asked to provide support for the differences. In most cases, these differences were attributed to changes in the number, or frequency, of activities. Inflation indices capture cost increases on existing units of production; they don't capture changes in volume. Examples of these types of adjustments are the Automated Meter Reading Savings (Adjustment 4.15) which reflects planned efficiencies from the automated meter reading project, and the Incremental Generation O&M adjustment for new plants (Adjustment 4.12).

Q. Please describe Exhibit RMP___(SRM-1).

A. Exhibit RMP___(SRM-1), which was prepared under my direction, is Rocky Mountain Power's Utah Results of Operations Report (the "Report"). As discussed above, the Base Period for the Report is the twelve months ended June 30, 2007, which has been normalized and is used to calculate the Test Period revenue requirement. The Report provides totals for forecasted revenues, expenses, depreciation, net power costs, taxes, rate base and loads in the Test Period. Electric plant in service, accumulated depreciation and amortization reserves are thirteen month averages. The Company has used a thirteen month average to better match new generation investment with maintenance and net power costs. The thirteen month average uses the month-end rate base for the thirteen months starting with June 30, 2008 and ending with June 30, 2009. All other rate base balances are an average of the beginning and ending amounts during the Test Period. The Report presents operating results for the period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit RMP___(SRM-1) is organized.

A. Starting with Tab 1 – Summary, is the Utah allocated results based on the Revised Protocol allocation methodology. Page 1.0 is the calculation of the rate mitigation cap which compares the revenue requirement from Rolled-In allocation to Revised Protocol and caps the increase at the lower of Revised Protocol or 101.19 percent of Rolled-In. The 101.19 percent cap is calculated as the weighted average of a 101.25 percent cap for nine months and a 101.00 percent cap for three months. Page 1.1, starting with the left-hand column (1), labeled Total

Adjusted Results is the Utah results of operations for the Test Period. The Total Adjusted Results column is carried forward from the results of operations summary, Page 2.2, and shows a forecasted ROE for Utah of 5.8 percent. The Price Change (column 2 of Tab 1, page 1.1) shows that an increase of $183.4 million in revenues is required to increase the return on equity from 5.8 percent to 10.75 percent in Utah. Column 3 reflects the Utah adjusted revenue requirement with the $183.4 million price increase included. Page 1.2, of Tab 1, supports the calculation of additional revenue-related uncollectible expense and franchise taxes associated with the price change requested in column 2. Page 1.3 details the calculation of the net operating income percentage. Page 1.4 shows the same details as page 1.1 under the Rolled-In rather than the Revised Protocol allocation method. It is used in calculating the rate mitigation cap on page 1.0.

Tab 2 details Total Company and Utah allocated results based on the Revised Protocol allocation methodology. Pages 2.3 through 2.39 contain Total Company and Utah allocated revenues, expenses and rate base detail by FERC Account. Supporting documentation for the data in Tab 2, along with the normalizing adjustments made to the Base Period data to reflect on-going costs of the Company, is provided under Tabs 3 through 8. The calculation of these amounts is described later in my testimony. Tab 9 is Tab 2 restated with the Utah allocation based on the Rolled-In allocation method. Tab 10 contains the calculation of the Revised Protocol allocation factors. The load forecast used for these factor calculations and to calculate the revenue and net power costs is explained further in testimony sponsored by Company witness Dr. Rife.

Tab 3 – Revenue Adjustments

Q. Please describe the procedures used to forecast the Company's Test Period revenues and explain the entries behind Tab 3, Revenue Adjustments.

A. The revenue forecast and adjustments are contained in Tab 3, which begins with an overview of assumptions used to forecast retail revenues and a brief explanation of each additional normalization adjustment made to other revenues. This is followed by a numerical summary (pages 3.0.2 – 3.0.10) by FERC account and allocation factor starting with actual revenue and summarizing each adjustment to get from the actual data to the Test Period. Pages 3.0.2 through 3.0.4 start with June 30, 2007 actual data and show the normalization adjustments necessary to calculate June 30, 2007 normalized revenues. Pages 3.0.5 through 3.0.7 start with June 30, 2007 normalized revenues and show the adjustments and changes necessary to calculate June 30, 2008 revenues. Likewise, pages 3.0.8 through 3.0.10 start with June 30, 2008 revenues and show the adjustments necessary to calculate the Test Period revenues for the twelve months ending June 30, 2009.

Revenue Normalization & Forecasts (page 3.1) – This tab has the incremental changes to walk from historical revenues to the Test Period forecasted revenues shown on page 3.1.6. It also includes the load forecasts for those periods for all states.

SO2 Emission Allowances (page 3.2) – Over the years, the Company's annual revenues from the sale of emission allowances have been uneven. Consistent with the Commission order in docket No. 97-035-01, the Company has amortized all sales of emission allowances over a four-year period. In addition, this adjustment includes forecasted sales through the end of the Test Period.

Revenue Correcting Adjustment (page 3.3) – In reviewing the historic data for the Base Period, the Company discovered two adjustments that needed to be made:

- The general business revenues in unadjusted results during calendar year 2006 are allocated by profit centers. The Company has profit centers in California, Oregon and Washington that cross state boundaries. This adjustment correctly assigns allocation factors based on the location of the revenues rather than profit centers for the affected jurisdictions.
- A review of FERC account 456, other electric revenues, was completed to verify that all of the revenues were correctly recorded in the Base Period. This adjustment corrects the allocation factor on several transactions where other electric revenues were assigned incorrect allocation factors in unadjusted results.

Wheeling Revenues (page 3.4) – During the Base Period various wheeling transactions took place which the Company does not expect to continue in the Test Period. These relate to prior period adjustments and contract terminations. This adjustment normalizes wheeling revenues to the anticipated level in the Test Period. The adjustment also includes proforma wheeling revenues for the twelve months ended June 2007, June 2008 and June 2009, including an adjustment for additional revenues associated with the Malin – Indian Springs transmission line.

Green Tag Revenues (page 3.5) – A market for green tags or Renewable Energy

Credits is developing where the tag or "Green" traits of qualifying power production facilities can be detached and sold separately from the power itself. This adjustment increases the revenues associated with green tag sales in the Mid and Test Period to account for the additional wind production MWh included in the GRID runs.

Q. Are there additional adjustments to revenue that are included in other portions of the Exhibit?

A. Yes. The following adjustments from other portions of my exhibits impact the revenue forecast:

K2 Risk Management System Removal (page 4.5)
Accounting Correction (page 4.7)
Net Power Cost Adjustment (page 5.1)
James River Royalty and Little Mountain Steam (page 5.5)
Upper Beaver Hydro Sale (Page 8.10)

These adjustments are described under the Tab in which they are located.

Tab 4 – Operation & Maintenance ("O&M") Expenses

Q. How is Tab 4 organized?

A. Tab 4 includes the O&M summary followed by the adjustments themselves.

Q. What is the O&M Summary and what is its purpose?

A. The O&M Summary is an overview that provides assumptions and itemizes the adjustments made to adjust O&M costs forward from the Base Period to the Test Period. It is the bridge between the O&M section in the results of operations (Tab 2) and the detail supporting the Company's Test Period O&M projections (Tab 4).

The O&M Summary begins on page 4.0 with a brief overview of assumptions used to forecast O&M. It is organized by FERC account and allocation factor starting with unadjusted data from the Base Period. Labor costs are adjusted separately so the second column subtracts the Base Period labor costs, leaving non-labor O&M. Each following column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-1), which contains a lead sheet. This lead sheet shows the FERC account affected by the adjustment, allocation factor, dollar amount and a brief description of the adjustment.

Q. Please describe the O&M numerical summary.

A. The numerical summary is found on page 4.0.1 through page 4.0.15. The detail in this tab supports pages 2.5 through 2.14. Each adjustment is listed in a separate column. These columns are totaled to produce the Base Period normalized O&M shown in the column on the right-hand side of the page, titled June 2007 Adjusted O&M on pages 4.0.1 through 4.0.4.

To walk O&M expenses forward from the Base Period to the Mid Period, the process is repeated as shown on pages 4.0.5 through 4.0.10. The Base Period labor costs were removed, leaving non-labor O&M. These costs are then escalated to Mid Period levels using Global Insight's indices for each FERC function, the result is then adjusted for items that weren't escalated based on an index such as incremental O&M and net power costs. The Mid Period labor costs were added back in with the other normalizing adjustments to produce the Mid Period (June 2008) O&M expense.

Finally, the process is repeated one more time to walk forward the Mid Period O&M to the Test Period, summarized on pages 4.0.11 through 4.0.15.

Q. Please describe the adjustments made to the Base Period non-labor O&M expense in Tab 4.

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

Non Recurring Expense Adjustment (page 4.2) – Accounting adjustments were made to expenses that were non-recurring in nature or related to prior periods. This adjustment removes these non-recurring items from the Base Period reducing total company operating expense by $9.7 million. Details on the specific adjustments can be found on page 4.2.1 of Exhibit RMP___(SRM-1).

Irrigation Load Control Program (page 4.3) – Incentive payments made to Idaho customers participating in the Schedule 72 irrigation load control program were initially booked as system allocated in unadjusted data. This adjustment corrects that allocation assigning these costs situs to Idaho consistent with the situs assignment of other Demand Side Management ("DSM") programs.

Blue Sky (page 4.4) – This adjustment removes costs associated with the Blue Sky program. The Blue Sky program is designed to encourage voluntary participation in the acquisition and development of renewable resources. To prevent non-participants from subsidizing the program, this adjustment removes administrative and other expenses directly associated with the program.

K2 Risk Management System (page 4.5) – This adjustment removes the effect of the K2 Risk Management system from results of operations. This project was capitalized during calendar year 2006. However, the project was writtenoff/retired during March 2007 as the project has been deemed not used and useful. This adjustment removed the expenses of the project which are included in the O&M template, and also removed the loss on the disposition of the asset in account 421 included in the revenue template in tab 3.

DSM Expenditure Removal (page 4.6) – Utah allows for recovery of Demand Side Management expenses through the system benefit charge (SBC) tariff rider. This adjustment removes Utah DSM costs in order to prevent a double recovery through the revenue requirement and the SBC tariff rider.

Accounting Correction (page 4.7) – In late 2006 it was discovered that in some cases offsetting entries in the labor pool were being charged to different accounts and/or locations. An entry in December 2006 corrected this for all of calendar year 2006. This entry removes the portion of the correction that relates to January – June 2006 which is out of period for this filing. An entry in September 2007 made similar corrections for January – June 2007. This adjustment is done in four parts on pages 4.7 through 4.7.3, which are summarized on page 4.7.3.

Cove Hydro Decommissioning (page 4.8) – The Cove Hydro electric plant was decommissioned in the fall of 2006. This adjustment removes the Cove operation and maintenance expense from results.

Postage Increase (page 4.9) - Effective May 14, 2007, the U.S Postal Service increased its rates by $0.02 from $0.29 to $0.31 for utility mailings. This adjustment reflects that additional cost by applying the two-cent increase to the average number of retail customers during the Base Period. This adjustment also includes the increased number of customers based on the company load forecast.

Wage & Employee Benefit Adjustment (page 4.10) – This adjustment is described later in my testimony.

MEHC Transition Savings (page 4.11) – After completion of the MEHC acquisition of the Company, certain cost saving programs were implemented. The major focus was to reduce the amount of corporate overhead by reducing the number of employees. Those employees whose positions were eliminated qualified for a change-in-control (“CIC”) severance payout based on years of service and salary. This adjustment removes the salary and severance paid to these former employees. The adjustment also adds back amortization expense over a three year period consistent with the Company’s application in Docket No. 07-035-04. This adjustment will be revised to comply with the Commission decision in the above referenced Docket after an order is received.

Incremental Generation O&M (page 4.12) – This adjustment annualizes the O&M expense associated with the Leaning Juniper Wind plant which was placed in service September 14, 2006. This adjustment also adds incremental operation and maintenance expenses for generating units that were not in service during the twelve months ended June 30, 2007 but will be in service during the twelve months ending June 30, 2009. The net power cost benefits associated with these additional resources are included in the net power costs in Tab 5.

MEHC Affiliate Management Fee Commitment (page 4.13) – This adjustment complies with the MEHC acquisition commitment 38 which states:

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

MEHC anticipates that the corporate charge to the Company will remain at $9 million during the five year period. This adjustment removes escalation to keep the cap at the commitment level.

Solar Photovoltaic Program Adjustment (page 4.14) – This adjustment reflects the estimated annual program costs associated with the pilot Solar Photovoltaic Utility Buy-Down Program co-sponsored by Utah Clean Energy and Rocky Mountain Power. This pilot photovoltaic project was implemented in September 2007 and is projected to operate at similar funding levels through 2011. The program will gather important information on the viability of a solar program funded by participating customers, tax incentives and a utility contribution.

Automated Meter Reading Savings (page 4.15) – The Company is replacing approximately 600,000 meters on the Wasatch Front with new radio equipped digital meters. This change will allow the Company to reduce over 90 meter readers. The Company is forecasting this investment will reduce Utah meter reading expense over $4 million for the test period, June 30, 2008 through June 30, 2009. The savings are attributed to reduced manpower, vehicles, and associated fuel.

Global Insight's Indices (page 4.16) – This page contains the second quarter 2007 forecast, released October 8, 2007. The indices for calendar year 2006 through 2009 and the percentage change from each year are shown. To better align these indices with the Company's test period we have averaged calendar years 2007 – 2008 to get June 2008 and calendar years 2008 – 2009 for June 2009. Page 4.16.1 provides an overview of the development and use of Global

Insight indices.

Q. Please describe how the Company forecasted labor costs for the Test Period.

A. Labor is adjusted on Page 4.10. The Company forecasts labor and labor-related costs by adjusting salaries, incentives, benefits, and costs associated with FAS 87 (Pension), FAS 106 (Post Retirement Benefits), and FAS 112 (Long Term Disability). These labor-related expenses were segregated from non-labor-related O&M costs so they could be escalated separately. Page 4.10.2 is a numerical summary starting with Base Period labor costs and adjusting them forward to reflect the Mid Period and Test Period level of expense, with the corresponding adjustment amount for each labor cost component. These summaries are followed by the detailed worksheets used to adjust the labor costs forward to the Test Period.

The first step was to annualize salary increases that occurred during the Base Period. This was done by identifying actual wages by labor group by month and when each labor group received wage increases. Those increases were then applied to wages that were paid prior to the effective date to annualize salary expense. The next step was to repeat that process by applying the wage increases for 2007 through 2009 to the annualized Base Period salaries to forecast the Mid Period and Test Period wages. The Company used union contract agreements to escalate union labor group wages, while increases for non-union and exempt employees were based on budgeted increases. This calculation was performed on pages 4.10.3 through 4.10.5.

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

A. Yes. As part of the Company's philosophy of delivering market competitive pay structured in a manner that benefits our customers with safe, adequate and reliable electric service at a reasonable cost the Company utilizes an incentive program. The incentive plan is described in the testimony of Company witness Mr. Erich D. Wilson. The net impact of this adjustment was a reduction in total company incentive compensation from $32.1 million in the twelve months ended June 30, 2007 to $28.9 million in the Test Period as shown on page 4.10.2.

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

A. Yes. Consistent with all other costs, pension and other employee benefit costs were itemized starting with the Base Period and walked forward to the Test Period. Total pension costs decrease by $29 million between actual data for June 2007 and the test period. These forecasts were provided by Mr. Wilson and supported in his testimony.

Q. Does Tab 4 cover any other items?

A. Yes. Payroll taxes were updated to capture the impact of the changes to employee salaries. This was calculated by applying the FICA tax rates to the net change in salaries and also to reflect the change in the social security cap for the Test Period.

Q. How were these changes incorporated into the O&M Summary?

A. The actual labor costs from page 4.10.11 through 4.10.13 were subtracted from the June 2007 unadjusted O&M on pages 4.0.1 through 4.0.4. After adjusting employee salaries and benefits to match the Base, Mid and Test Period, these costs were spread back to FERC accounts based on the same percentage that existed in the Base Period.

Q. Does the Wage adjustment include any adjustment for changes in workforce levels?

A. No. The wage and employee benefit adjustment assumes a constant level of workforce. The labor savings from the reduction in the number of employees due to the MEHC transaction was reflected in the MEHC Transition Savings adjustment discussed earlier in my testimony.

Tab 5 – Net Power Cost Adjustments

Q. How was the Net Power Cost adjustment calculated?

A. The Net Power Cost adjustment normalizes revenues and expenses in a manner consistent with normalized operation of production facilities. Page 5.1.0 is an overview of the $1,092 million in total Company net power costs included in the filing. The normalized Net Power Costs for Base, Mid and Test Periods contained in tab 5 are explained in Mr. Widmer's testimony.

Q. Please describe the Net Power Cost adjustments included in Tab 5.

A. **Net Power Cost Adjustment (page 5.1) –** Page 5.0 is an overview of the power costs for the Base, Mid and Test Periods. Page 5.1.0 of the Report is a numerical summary of the same comparing the normalized Net Power Costs for the Base, Mid and Test Periods developed by Mr. Widmer to the actual Base Period amounts to determine the amount of the adjustment. This is followed by the FERC account and allocation summary and the GRID reports for each period on pages 5.1.1 through 5.1.30.

The Net Power Cost adjustment normalizes steam and hydro power generation, fuel, purchased power, wheeling expense, and sales for resale in a manner consistent with the contractual terms of the Company's sales and purchase agreements. It also normalizes hydro, weather conditions and plant availability as described in Mr. Widmer's testimony. The revenue amounts from this adjustment flow to pages 3.0.2 through 3.0.10, and the expense amounts flow to 4.0.1 through 4.0.15.

BPA Exchange (page 5.2) – The Company receives a monthly BPA purchase power credit from BPA. This credit is treated as a 100 percent pass-through to eligible customers. Both a revenue credit and a purchase power expense credit are posted to unadjusted results. The revenues are reversed as part of the revenue normalization adjustment. This adjustment reverses the BPA purchase power expense credit recorded during the test period.

Green Tags (page 5.3) – This adjustment removes green tag purchase costs. These green tag purchases were related to the Blue Sky program and should be recorded below the line.

West Valley Plant (page 5.4) – The Company has informed PPM Energy, the owner of the West Valley plant, of its intent to terminate the West Valley lease on May 31, 2008. As a result, the lease payment, operation and maintenance expenses, electric plant in service balances, and accumulated reserve associated with this contract have been adjusted in the Base and Mid Periods, and all costs associated this plant have been completely removed from the test period. This treatment is consistent with the modeling of net power costs.

After the MEHC transaction closed on March 21, 2006, the West Valley lease expense was reduced by $417,000 per month. In Docket No. 06-035-21 the Company deferred the savings associated with this reduction prior to the reduction being reflected in Utah rates. Subsequent to the inclusion of this reduction in rates the Company began amortizing this deferral through May 31, 2008, the remaining portion of the contract. This amortization is included in the Base and Mid Periods.

James River Royalty Offset & Little Mountain (page 5.5) – On January 13, 1993, the Company executed a contract with James River Paper Company with respect to the Camas mill, later acquired by Georgia Pacific. Under the agreement, the Company built a steam turbine and is recovering the capital investment over the twenty-year operational term of the agreement as a royalty offset. The agreement also includes payment of royalties from the Company to James River based on contract provisions. Included in Rocky Mountain Power's net power costs as purchased power expense are the contract costs of energy for the Camas unit, but GRID does not include an offsetting revenue credit for the capital cost recovery and maintenance cost recovery amounts. Adjustment 5.5 adds this royalty offset to account 456, Other Electric Revenue, for the Test Period.

This adjustment also normalizes the ongoing level of steam revenues related to Little Mountain. Contractually, the steam revenues from the Little Mountain plant are tied to natural gas prices. GRID models the cost of running the Little Mountain plant but does not include the offsetting steam revenues. This adjustment aligns the steam revenues to the gas prices modeled in GRID.

Tab 6 – Depreciation and Amortization Expense Adjustments

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

A. Detailed worksheets supporting the calculation of the Test Period depreciation and amortization expense contained in Tab 2 are provided in Tab 6. The depreciation and amortization expense amounts included in the Test Period are summarized on pages 6.1 and 6.1.1. Depreciation and amortization expense is calculated by applying functional composite depreciation and amortization rates to forecast plant balances. Forecast plant balances are developed as described in Tab 8. A description detailing the depreciation and amortization expense calculation can be found on page 6.0.

The methodology of applying composite rates to forecast plant balances results in a Test Period depreciation expense of $456.1 million and amortization expense of $49.3 million. The calculation of these amounts is detailed on pages 6.1.2 to 6.1.17. The $456.1 million of depreciation expense reflects the depreciation rates proposed by the Company on August 31, 2007 in Docket No. 07-035-13. Test Period depreciation expense does not reflect any changes made to depreciation rates subsequent to the August 31, 2007 filing.

Included in Test Period depreciation and amortization expense are items in addition to the amount calculated as described above. Adjustment 6.3 Hydro Decommissioning adds $3.6 million to depreciation expense, resulting in a Test Period depreciation expense of $459.6 million. Adjustment 8.6 Grid West Loan and adjustment 8.11 Powerdale Decommissioning contain amortization items which are included in the Test Period amortization expense. Amortization of the plant acquisition adjustment in account 406 is held constant at its Base Period amount. Account 407, amortization of unrecovered plant, is adjusted to remove a partial year amortization of the Powerdale unrecovered plant deferral, which is stated at an annual Test Period amount in adjustment 8.11 Powerdale Hydro Electric Facility. Reflecting these additional items increases Test Period amortization expense to $58.4 million.

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

A. Accumulated depreciation and amortization balances for the Test Period are calculated by applying depreciation and amortization expense and plant retirements to the June 2007 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2007 to June 30, 2009. The monthly balances from June 2008 through June 2009 are used to calculate the 13 month average reserve balance in the Test Period. This averaging methodology is used to align the treatment of the reserve balances with the treatment of the EPIS balances explained on page 8.0. The reserve balance calculations are detailed on pages 6.2.2 to 6.2.11.

Q. Will this adjustment be updated when new rates are approved by the Commission?

A. Yes. The depreciation and amortization expense and balances will be updated for the depreciation rates approved by the Commission in Docket No. 07-035-13.

Q. Please describe any additional depreciation adjustments included in the case.

A. The following adjustments were made to depreciation and amortization expense.

Depreciation/Amortization Reserve (page 6.2) – This adjusts the depreciation and amortization reserve for the additional depreciation and amortization expense from the plant additions added to rate base in adjustment 8.7. This adjustment also reflects plant retirements calculated in adjustment 8.13.

Hydro Decommissioning (page 6.3) – Based on the August 31, 2007 depreciation study filing in Docket No. 07-035-13 an additional $19.4 million is required for decommissioning of various hydro facilities. The proposed rates are scheduled to become effective January 2008. This adjustment includes the proposed change in the Mid and Test Period. This adjustment will be updated for any changes in the final depreciation case order.

Tab 7 – Tax Adjustments

Q. Please describe the process of forecasting Test Period taxes for use in the results of operations report.

A. An explanation of the Company's method for projecting the Test Period tax expense is provided on page 7.0 of that tab. For purposes of this discussion, tax expense is separated into the following categories: Schedule M items, Deferred Income Tax Expense, Taxes other than Income Taxes, Renewable Energy Tax Credit and Utah Gross Receipts Tax removal. Detail supporting the forecast of the Test Period tax expense is provided in Tab 7. For purposes of calculating deferred income taxes on capital additions in the case the Company has implemented full normalization of basis differences on a prospective basis.

Schedule M Items (page 7.1) – The Schedule M items at June 30, 2007 were used to forecast June 2009. Non-utility items, items that are recovered under separate tariff, and other non-recurring items were removed from the June 2007 base period before forecasting. For example, Schedule M items related to the Grid West Note Receivable, FAS 87/88 Write-off and Glenrock Mine Reclamation were removed. Normalizing adjustments were then added, such as adjustments to Pension & Benefits and SO2 Emission Allowances. The Schedule Ms were also adjusted for Pollution Control property amortization and the Production Activity Deduction. Depreciation differences on capital additions were generated in order to bring the Schedules Ms in line with the June 2009 test period. The Schedule Ms were then used to develop deferred income tax expenses and balances for June 2009.

Deferred Income Tax Expense (page 7.2) – The non-property-related Schedule M items were used to develop the deferred income tax expense. The property-related deferred income tax expense was generated using the capital additions and resulting book and tax depreciation. Normalizing adjustments were added consistent with the Schedule M items. The deferred income tax expense was then used to develop the deferred tax balances for June 2008 and June 2009.

Renewable Energy Tax Credit (page 7.3) – The Company is eligible for a federal income tax credit as a result of placing wind generating plants in service. The tax credit is based on the generation of the plants, and the credit can be taken for ten years on qualifying property. Under the calculation prescribed by IRC Code Sec. 45(b)(2), the most current renewable electricity production credit is 2.0

cents per kilowatt hour of the electricity produced from wind energy.

Taxes Other Than Income Taxes (page 7.3) – Property tax expense for test period June 2009 was forecasted by adjusting year to date accruals through June 30, 2007 for known or anticipated changes in assessment levels through June 2009. Payroll tax for the test period June 2009 is included in O&M as part of the Labor costs. The payroll taxes were developed from the calculation of labor for the test period ended June 2009 as discussed in the O&M Tab. The remaining miscellaneous taxes other than income were developed using fiscal year June 2007 accruals and adjusting for known or anticipated changes through test period June 2009. The net-to-gross calculation incorporates some of the miscellaneous other taxes to add an incremental cost to the incremental revenue requirement.

Utah Gross Receipts Tax Adjustment (page 7.5) – In 2006 the governor of Utah approved Utah House Bill 34 which repealed the gross receipts tax. The Company has removed this expense from its results.

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

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

Tab 8 – Rate Base

Q. Please describe how the Company developed the rate base projections used in the Test Period.

A. The detail for rate base for the Test Period is described in Tab 8. The key assumptions used in forecasting the Test Period rate base are summarized on page 8.0. The June 30, 2007 unadjusted balances, by FERC account, are included in the left-hand column of Pages 8.0.1 through 8.0.22. These pages summarize the incremental changes to walk rate base forward from June 30, 2007 to June 30, 2008 and June 30, 2009, and show the rate base amounts included in the Mid and Test Periods. The column "Test Period Jun 08 – Jun 09' is the average rate base summarized on pages 2.21 through 2.39 of Tab 2 - Results of Operations. Pages 8.0.23 through 8.0.132 detail each normalization adjustment made to rate base between the June 30, 2007 and June 30, 2009 by year.

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

A. **Cash Working Capital (page 8.1) –** This adjustment is necessary to true-up the cash working capital for the normalizing adjustments made in this filing.

Trapper Mine (page 8.2) – The Company owns a 21.4 percent share of the Trapper Mine, which provides coal to the Craig generating plant. This investment is accounted for on the Company's books in account 123.1, Investment in Subsidiary Company, which is not included as a rate base account. This adjustment adds the Company's portion of the Trapper Mine net plant investment to rate base in order for the Company to earn a rate of return on its investment. The normalized coal cost from Trapper Mine in net power costs include O&M costs but does not include a return on investment.

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

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

Customer Advances for Construction (page 8.5) – Customer advances were recorded in June 2007 unadjusted data to a corporate cost center location rather than state-specific locations. This adjustment corrects the allocation of customer advances.

GRID West Loan (page 8.6) – In docket No. 06-035-163 the Company filed an accounting application on August 8, 2007 requesting approval to defer GRID West costs and amortize them over three years. At this time, the Commission has had a hearing on the docket but has not yet issued an order. The Company is treating this consistent with the application and will update this adjustment when an order is received.

Plant Additions (page 8.7) – To provide a better match between the system infrastructure investment requirements and the load required to serve our customers, the Company has identified capital projects that will be completed by the end of the Test Period. This information was provided by Company business units, which were asked to identify capital expenditures that will be used and useful prior to the end of the Test Period. Additions by functional category are summarized, indicating the in-service date and amount by project. The accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements as described in the depreciation section described earlier.

Miscellaneous Rate Base (page 8.8) – This adjustment includes four parts as described below:

- The Company is removing its cash balance from rate base to avoid earning its rate of return on the Company's cash balance.
- The projected balance of the Company's coal plant fuel stock is increasing due to increases in the cost of coal and the number of tons stored at each site. This adjustment adds the anticipated increases in fuel stock.

- Regulatory assets and liabilities are adjusted to their Mid and Test Period forecast levels.
- The accumulated provision for Electric Plant Acquisition Adjustment is adjusted to its Mid and Test period balances.

American Fork Hydro Decommissioning (page 8.9) – The American Fork hydro electric plant is currently being decommissioned, with completion expected by the end of 2007. As of June 2007 only $569,500 had been collected for decommissioning. It is expected to cost $3,750,000 to decommission the plant. This adjustment adds the decommissioning difference into the accumulated depreciation reserve and removes the net American Fork assets from results and also removes the associated O&M. Since Test Period depreciation expense is calculated on adjusted plant balances, which reflect this adjustment, depreciation expense related to this plant is also eliminated from the test period.

Upper Beaver Hydro Sale (page 8.10) – The Company entered into an agreement to sell the Upper Beaver hydro facilities to the city of Beaver, Utah. The sale closed on September 14, 2007. This adjustment removes the net investment and operating costs associated with the Upper Beaver plant from results.

Powerdale Hydroelectric Facility (page 8.11) – Powerdale is a hydroelectric generating facility located on the Hood River in Oregon. This facility was scheduled to be decommissioned in 2010; however, in 2006 a flash flood washed out a major section of the flow line. The Company determined that the cost to repair this facility was not economical and determined it was in our customers best interest to cease operation of the facility.

The Company has applied with the Commission in Docket No. 07-035-14 for an order (A) authorizing the Company to transfer its undepreciated net investment in the Powerdale Plant from FERC account 101 (Electric Plant in Service) to FERC account 182.2 (unrecovered Plant and Regulatory study costs), (B) permitting the Company to record decommissioning costs in FERC account 182.2, and (C) authorizing the Company to establish amortization periods for these amounts. This adjustment is consistent with the Company's filings in this Docket. This adjustment will be updated once a final decision in this docket is received.

Customer Service Deposits (page 8.12) – Utah requires the Company to include customer service deposits as a reduction to rate base. This adjustment reflects the deposits in results as a rate base deduction and also includes the interest paid on the customer service deposits. This treatment was stipulated in Utah Docket No. 97-035-01 and has been upheld in subsequent dockets.

Retirements (page 8.13) – Retirement rates used in this filing were calculated using a five-year historical average of retirements. These rates are applied to the monthly forecast plant balances to calculate plant retirements through the Test Period. The retirements reduce electric plant in service each month between the Base Period and the Test Period.

Q. Does this describe all of the adjustments to rate base for the test year?

A. Yes.

Q. Please describe the rest of the Report.

A. **Tab 9, Rolled-In**, is a re-cast of Tab 2 based on the Rolled-In allocation methodology. This information is being provided pursuant to Commission order from the application of the Company for an investigation of inter-jurisdictional issues in Docket No. 02-035-04.

Tab 10, Allocation Factors, summarizes the derivation of the jurisdictional allocation factors using the MSP Revised Protocol allocation methodology. These factors are based on the loads provided by Mr. Klein, summarized in Tab 10.2 and the plant balances contained in this Report.

Q. Would you describe the purpose of Exhibit RMP___(SRM-2)?

A. Yes. To comply with the filing requirement the Company has provided three additional Results of Operation reports. They are the Company's Unadjusted results of operation for twelve-months ending June 30, 2007 with both total Company and Utah allocated amounts. The Base Period, which is the normalized results of operation for that same period, again with total Company and Utah allocated. Finally the Mid Period results of operation for the twelve-months ending June 30, 2008.

Q. How is this Exhibit organized?

A. Each period has six tabs, with the exception of the tab identifying the period the other five tabs are titled the same. They are; Tab 1 Summary, Tab 2 Results of Operation, Tab 9 Rolled-In Methodology, Tab 10.1 Allocation Code Factors and Tab 10.2 Demand and Energy Loads. This numbering scheme and the content are consistent with that used in Exhibit RMP___(SRM-1). The individual tabs for the

Unadjusted, Base and Mid Period data are comparisons on a Total Company and Utah allocated basis of those periods to the Test Period results of operation. Tab 1 contains the calculation of the Revised Protocol cap and the Utah allocated results for that period for Revised Protocol and Rolled-In. Tab 2 has the results of operation summary by function and FERC account detail for Total Company and Utah allocated. Tab 9 is Tab 2 restated based on Rolled-In allocation factors. Tab 10.1 includes the Revised Protocol allocation factors and support for their calculation. Tab 10.2 summarizes the demand and energy for each period which was used for calculation of the factors.

Q. From your analysis what do you conclude about the overall reasonableness of the Company's forecasted test year in this proceeding?

A. The Test Period that the Company has presented in this case best reflects the conditions in the rate-effective period. Based on this Report, the Company will need this requested rate increase to recover its cost of serving Utah customers and provide a fair and equitable return for shareholders.

Q. Does this conclude your direct testimony?

A. Yes.