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

A. My name is Gregory N. Duvall, my business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232, and my present title is Director, Long Range Planning and Net Power Costs.

Q. Have you previously filed testimony in this case?

A. Yes. I filed direct testimony and supplemental direct testimony in this case.

Q. Will any other witnesses be presenting rebuttal testimony for Rocky Mountain Power with this filing?

A. Yes. In addition to myself, two additional witnesses will present rebuttal testimony in support of Rocky Mountain Power's Energy Cost Adjustment Mechanism (ECAM): Dr. Karl A. McDermott, Ameren Distinguished Professor of Business and Government at the University of Illinois at Springfield and a Special Consultant to National Economic Research Associates, Inc. ("NERA"), and Mr. Frank C. Graves, Principal at The Brattle Group.

Q. What is the purpose of your rebuttal testimony?

A. I agree with the Division of Public Utilities ("Division") position that an ECAM could be in the public interest and that the case should proceed to Phase II, as presented in the testimony of Mr. Charles E. Peterson. I respond to other issues raised by the Division, presented in Mr. Peterson's testimony; the Utah Office of Consumer Services ("OCS"), presented in the testimonies of Ms. Michelle Beck and Mr. Paul Chernick; the UAE Intervention Group ("UAE"), presented in the testimony of Mr. Kevin C. Higgins; and the Western Resource Advocates

("WRA"), presented in the testimony of Ms. Nancy L. Kelly.

Summary of Testimony

Q. Will you please summarize the topics you will cover in your rebuttal testimony?

A. In my rebuttal testimony, I cover the following issues:

- First, I present RMP's response to the issues raised regarding elimination of the Energy Balancing Account (EBA);
- Second, I address the specific issues surrounding criticism of the analyses presented in my supplemental direct testimony;
- Third, I discuss concerns raised about incentives associated with the implementation of an ECAM;
- Fourth, I address the "threshold" issue raised by OCA that the Company is too dependent on market energy; and
- Fifth, I address the concern raised by Mr. Peterson that RMP may possibly over earn with an ECAM.

Q. What is the overall recommendation of RMP in this rebuttal filing?

A. RMP recommends that the Commission find an ECAM is needed in Utah and is in the public interest. Based on this finding, the Company recommends that the Commission proceed with Phase II of this docket.

Q. What is your overall reaction to the testimony filed by the parties in this docket?

A. My overall response is twofold. First, I am pleased that the Division has taken the position that an ECAM could be in the public interest and that the case should proceed to Phase II. Second, I am disappointed with the testimonies from other parties as it is clear that there is a desire on their behalf to continue to set rates for RMP with respect to net power costs through protracted litigation over computer modeling techniques and inputs, which places the Commission in the position of being the referee to determine which model or modeler is least inaccurate. This is the status quo in Utah today and has proven to be a system that fails to accurately allow RMP to recover its prudently incurred net power costs. In this rebuttal testimony, I expand on my previous testimonies and present evidence that RMP's Utah customers have systematically under paid for prudently incurred net power costs in an amount that exceeds $300 million over the last eight years.

RMP has an interest in recovering its prudently incurred net power costs and is willing to abandon forecasts of net power costs in favor of allowing the Commission to determine if net power costs incurred by RMP are prudent. Recovery of prudent costs is the objective of regulation; it is good for customers and makes RMP whole – nothing more, nothing less. Determining prudence – unlike refereeing dueling power cost models - is a straightforward process which the Commission is well suited to address. Historically, the Commission has rarely found imprudence with regard to net power costs, and RMP believes the Commission will rarely find that the Company to be imprudent in the future. That said, if the Commission finds a particular element of net power costs to be imprudent in the future, customers will not pay for such costs.

Elimination of the Energy Balancing Account

Q. Both Ms. Beck and Ms. Kelly raise concerns that in 1990, the Company proposed to eliminate the EBA and the Commission found that to be in the public interest. Ms. Beck asserts that this background requires the Company must meet a higher evidentiary standard in this case. How do you respond?

A. The Company does not agree that the standards are different today than they were in 1990; only the facts and circumstances have changed. Mr. Peterson, testifying for the Division of Public Utilities reached the same conclusion. After describing factors that had changed from the early 1990s to today, Mr. Peterson concluded "that the previous issues surrounding the termination of the previous EBA are not particularly relevant today." (Peterson at 355-356)

In the Company's direct and supplemental direct filings, a number of facts were presented that identified changes in the level and nature of net power costs, market prices, resource mix and fuel supply. Some of these facts were not addressed in the testimony of the other parties (or were supported by Mr. Peterson) and remain uncontested, and others were only addressed by OCS witness Mr. Chernick. Moreover, in my supplemental direct testimony I emphasized the need to accurately reflect net power costs in rates. Modeling net power costs may have worked well in 1990, but it is no longer the most accurate way to implement cost of service ratemaking.

Q. Please explain.

A. In 1990, Utah loads were about 12 million megawatt-hours, which is about half of what they are today. In addition, net power costs are about twice what they were in 1990 at $8.58 per megawatt-hour. This means that a 10 percent forecast variance[1] of net power costs results in four times the error to in-rates net power costs today as compared to 1990. In dollars, this means if net power costs were under forecast[2] by 10 percent, customer prices today would under collect $40 million each year. In 1990, the same 10 percent forecast variance would have resulted in a difference between the forecast net power costs and cost of service of $10 million per year. The significant increase in the amount of dollars that could be at risk at the same level of forecast variance in Utah combined with the likelihood of increased forecast variance due to the significant increase in volatility and uncertainty surrounding the components of net power cost has lead RMP to recommend implementation of an ECAM at this time to better serve the public interest.

Q. Is a 10 percent forecast variance a reasonable assumption?

A. Yes. For example, in 2008, in-rates net power costs in Utah were $15.58 per megawatt-hour, and actual net power costs were $18.92 per megawatt-hour, which represents a forecast variance of 19.23 percent. In addition, the Company forecasts net power costs to increase by about 25 percent by 2011 compared to what is currently in rates in Utah. This magnitude of change could give rise to even a larger forecast variance.

[1] The term "forecast variance" as used in this testimony refers to the difference between the results of modeled net power costs approved by the Commission for inclusion in rates and actual net power costs and is not meant to imply that modeled net power costs use a forecast test period.

[2] The term "forecast" as used in this testimony refers to modeled net power costs and is not meant to imply that modeled net power costs use a forecast test period.

Q. Are there any differences in the market rules between 1990 and today that would work to increase forecast variance?

A. Yes. In 1990, the Federal Energy Regulatory Commission required wholesale transactions to be cost-based. This served to substantially limit the price that could be charged for the purchase and sale of wholesale power. Today, wholesale power is a commodity and is priced at whatever the market will bear.

Q. Does RMP control the forecast variance in net power costs for ratemaking?

A. No. In the context of this discussion, forecast net power costs and the associated variance mean the level of net power costs ultimately approved by the Commission for inclusion in Utah rates, not the forecast net power costs as filed by the Company. Under the current Utah regulatory treatment of net power costs, the level of net power costs in rates reflects the Commission's assessment of the competing forecasts and forecast adjustments in contested cases, or reflects the joint view of the parties and the Commission in cases where net power costs are determined as part of a settlement. Regardless of whether a case was litigated or settled, the outcomes have varied significantly from the cost of providing service to Utah customers.

Q. Mr. Chernick suggests that if RMP is concerned about its ability to forecast net power costs, then it should improve its model rather than implement an ECAM. Would this fix the problem with the current paradigm?

A. No. As stated above, RMP does not determine the in-rates forecast of net power costs. In addition, Mr. Chernick admits that "any forecast of the loads on particular hours conducted more than a few days in advance will be wrong." (Chernick at 294) Since loads are significantly influenced by weather, the same conclusion would be applicable to other components of net power costs that are affected by weather – namely hydro and wind. Not adopting an ECAM puts the Company at risk of not collecting from customers the cost of providing service to them and does not meet the regulatory objective that the Commission should be pursuing of providing for just, reasonable and adequate rates and charges. According to Mr. Chriss, this is the "most basic standard regulatory objective". (Chriss at 6).

RMP believes that all parties and its customers would be best served by revising the regulatory process to allow the Commission to judge the prudence of the net power costs incurred in an historic period rather than perpetuate the current process in which the Commission is forced to act as referee in the battle of competing forecasts of volatile of power costs – forecasts that may be reasonable but are admittedly inaccurate. RMP simply wants a reasonable opportunity to recover its actual prudent net power costs, and the current regulatory process does not provide that.

Q. How does an ECAM affect forecast risk?

A. An ECAM, depending on its structure, can mitigate or eliminate forecast risk and bring retail prices closer to or equal to cost of service on a sustained basis. Forecast risk is theoretically a risk to both customers and RMP, but in the Company's recent Utah experience, net power costs in rates have consistently been under-forecast, resulting in the Company not recovering its prudent costs and customers receiving service for which they have not compensated the Company. A paradigm shift, such as moving to an ECAM, is the only way RMP can conceive of removing the forecast risk and providing customers with prices that reflect cost of service with respect to net power costs.

Q. Both Ms. Beck and Mr. Higgins indicate that changes since 1990 have been made in Utah that improve the Company's ability to recover costs? Does that diminish the need for an ECAM?

A. No. The changes cited are frequent rate cases, use of a forecast test period, pre-approval of significant new resources under the Energy Resource Procurement Act, and single item rate case for major plant investment. Errors in forecasting net power costs will continue even with these changes for reasons already cited. Later in my testimony, I will discuss how the legislative changes resulting in more scrutiny of resource procurement and in major plant addition cases largely eliminate concerns raised by several parties about proper incentives.

Issues Regarding Company Analysis

Q. Did any party raise issues about the Company's analysis presented in your direct or supplemental direct testimonies?

A. The only witness that attempted to respond to my analyses was Mr. Chernick. No other party raised any issues as to the integrity of the analyses. Mr. Higgins concluded that the Company's cost structure is not sufficiently volatile to justify adoption of an ECAM without indicating how volatile the Company's cost structure would have to be to change his recommendation. Ms. Beck concludes that the Company has not demonstrated a need for such a mechanism without identifying what level of demonstration would change her recommendation. Ms. Kelly concluded that an ECAM is not in the public interest, expressing concern over incentives and disincentives with no comments on the Company's analyses. The Division recommended moving to Phase II, signaling that it does not oppose the showing of need for some form of ECAM.

Q. Mr. Chernick claims that RMP's failure to breakdown the historic differences shown in Table 1 of your Supplemental direct testimony undermines RMP's arguments about the need for an ECAM. How do you respond?

A. RMP disagrees with Mr. Chernick's contention. In its direct and supplemental direct filings, RMP provided an explicit and quantitative analysis of the risks of fluctuating power costs, such as the magnitude and nature of the risks.

Q. Related to this, on page 8 of his testimony, Mr. Chernick suggests that the Company could have made a number of additional comparisons. Have you made these additional breakdowns and comparisons?

A. Yes. To avoid controversy on this issue, Exhibit RMP___(GND-1R) and Exhibit RMP___(GND-2R) to this testimony provide the comparison of the selected net power cost components during the periods when rates are in effect.

Q. Please describe Exhibit RMP___(GND-1R).

A. Exhibit RMP___(GND-1R) has six columns, labeled A through F. Each column represents a rate-effective period. The first rate-effective period began January 1, 2002, after the end of the energy crisis that occurred in 2000 and 2001. The "In-Rates" section of column A is based on the Commission's Order in Docket No.

01-035-01. These rates were in effect for 27 months, as shown at the top of the exhibit. The net power cost row is the sum of all 27 months and is not directly comparable to the test period amount without converting it to a 12-month equivalent. Exhibit RMP___(GND-1R) shows the actual net power costs, in-rates net power costs and the difference between the two for each of the six rate-effective periods that have occurred in Utah from January 1, 2002 through September 30, 2009. The last line of Exhibit RMP___(GND-1R) shows the under recovery or over recovery of net power costs from Utah customers for each of the rate-effective periods and is determined by multiplying the difference between the average in-rates net power costs and actual net power costs on a dollar per megawatt-hour basis by the Utah load for the same rate-effective period. Under recoveries are shown as negative numbers. For example, column F shows an under recovery of net power costs from Utah customers in the amount of $26.6 million for the approximately five months that current rates set in Docket No. 08-035-38 have been in place. Mr. Graves provides a number of observations about this data in his rebuttal testimony.

Q. Please describe Exhibit RMP___(GND-2R).

A. Exhibit RMP___(GND-2R) provides the comparisons and valuations suggested by Mr. Chernick on page 8 of his direct testimony. The in-rates versus actual differences in the price of natural gas, market purchases and market sales as well as differences in the volume of natural gas and wind generation are identified and valued. The exhibit shows that over the last eight years, each of these individual data elements has been uncertain and volatile, and has been a key driver that has contributed to the differences between in-rates and actual net power costs.

Q. Was there any other criticism to the analysis presented in Table 1 of your supplemental direct testimony?

A. Yes. Mr. Chernick noted that Table 1 was not adjusted to Utah-regulatory terms and that revenues were not included as an offset to net power costs and as a result, the claims to under recovery of net power costs were overstated.

Q. How do you respond to the criticism of actual net power costs not adjusted to Utah-regulatory terms?

A. The only item that was not factored into the table was the adjustment for the SMUD revenue imputation. Given that the SMUD adjustment is small in comparison to the overall forecast variance, assuming a maximum amount of $10 million a year on a total Company basis, or $4 million a year allocated to Utah, my conclusions from Table 1 remains the same.

Q. How do you respond to the criticism that revenues were not included as an offset to net power costs?

A. Exhibit RMP___(GND-1R) includes revenues as an offset to net power costs and shows that revenues do not always offset changes in net power costs. For example, Column A indicates that there would not be any additional revenue to offset the under-recovery of net power costs because the actual load is lower than the in-rates load. Thus, consideration of revenues added to the under recovery of net power costs during that rate-effective period. Column B shows that the actual load is higher than the in-rates load. However, to offset the under-recovered net power costs, the revenue from the additional load would have to be at about

$152.14 per megawatt-hour. In all, there has been a substantial amount of time where loads were below forecast while net power costs were above forecast. When this occurred, there was no revenue offset to help mitigate higher than expected net power costs.

Q. Why did you only include revenues associated with net power costs and not total retail revenues?

A. As stated above, revenues do not always work to offset net power costs. Moreover, the purpose of this docket is to address the recovery of net power costs. Regulatory recovery issues associated with non-net power cost components of revenue requirement are not at issue in this docket.

Q. What is your overall conclusion from the information presented in Exhibit RMP___(GND-1R)?

A. Using forecast net power costs over the past eight years has resulted in Utah customers paying over $300 million less than cost of service even after accounting for changes in revenues and adjusting for Utah-regulatory terms described previously.

Q. Mr. Chernick quotes you as saying "hedging instruments are generally available to mitigate the risk of uncertainty in the price of natural gas and wholesale power for a known net open position." (Chernick at 233) Based on this, he concludes that historical differences between the Company's forecast and actual net power costs have not been driven in part by changes in gas and electric prices. Is this a reasonable conclusion?

A. No. The operative phrase in the quote is "for a known net open position." The

Company has made it clear throughout its testimony that its open position varies each day, and even each hour. A “known net open position” is only known for a short time. Mr. Chernick’s conclusion would only be true if the Company’s open position stayed constant over the period a given rate is in effect and at the level that has been included in the determination of that rate. This is clearly not the case and is well understood by Mr. Chernick since he quotes my Supplemental direct testimony again one page later in his testimony where he says I say that “significant variations subsequently occur in the net open position through the actual period as a result of the large, uncontrollable and unpredictable volatility in both loads and resources that occur simultaneously with large, uncontrollable and unpredictable volatility in prices of natural gas and electricity.” (Chernick at 268) The stochastic analysis presented in my Supplemental direct testimony addressed the combined uncertainty of loads, forced outages, and hydro generation assuming that RMP was perfectly hedged based on a “known net open position.” The results of that study, conducted for calendar year 2012, showed that net power costs increased by $80 million and risk exposure increased by $666 million due solely to the combined volatility of loads, forced outages, and hydro generation.

Q. Did any party attempt to rebut the stochastic analysis?

A. Mr. Chernick was the only witness to address the stochastic study. His primary criticism, which he labels as “most fundamental,” is that if the Company is concerned that its forecast of net power costs is consistently understated, then the Company should change models. I discussed this earlier in my testimony as a solution that cannot fix the underlying fundamental fact that due to the volatility of multiple variables, changing models will not improve the accuracy of forecasting net power costs for the Company's system. And as described earlier, in-rates net power costs are a result of the regulatory process, not the model. Moreover, changing models will not eliminate the protracted debate over inputs to the model and modeling techniques. These include debates over the vintage of load forecast and commodity price forecast, coal price forecasts, planned outage schedules, forced outage rates, ramping, value and costs of start-up energy, screens, market caps, SMUD shaping, biomass non-generation agreement, short-term firm transmission synchronization, transmission imbalance, Cholla capacity upgrades, wind integration costs, minimum loading, heat rate de-ration, and what updates are allowed.

Q. What were Mr. Chernick's other criticisms of the stochastic study?

A. He had two other criticisms. First, he claimed that the study overestimated the effect of load variability on the Company's earnings because it did not reflect changes in retail revenues. Second, he claimed that the load variability in the stochastic analysis was quite extreme.

Q. How do you respond to Mr. Chernick's first additional criticism?

A. Mr. Chernick states that iterations with higher loads would have higher revenues, yet fails to point out that iterations with lower loads would have lower revenues. If anything, the change in revenues over all of the stochastic iterations would tend to offset each other.

Q. Why do you say that revenues would tend to offset each other when net power costs do not?

A. Circumstances matter on the cost side, where they do not on the revenue side. For example, when loads increase or decrease, revenues increase or decrease symmetrically. Factors such as power plant availability, fluctuations in wholesale market prices, drought or floods, natural gas prices, and transmission outages have little to no impact on the average retail rate during a rate-effective period. In a stochastic run, where the 100 iterations average to the mean, changes in revenues will largely cancel out.

Net power costs, on the other hand, are highly affected by all of the factors identified above and are influenced primarily by marginal cost as opposed to average cost. Not only do such factors impact net power costs, they do so asymmetrically, since costs are unbounded on the high side and cannot go below zero on the low side. These asymmetric distributions of net power cost input elements have been widely discussed in the integrated resource planning process and are documented in Chapter 7 the 2008 Integrated Resource Plan (page 163).

Q. How do you respond to Mr. Chernick's second additional criticism?

A. While Mr. Chernick may not like the stochastic parameters used in the integrated resource planning models, they are generally supported by the Commission.

Q. Mr. Chernick claims that his criticisms of the stochastic model runs "undermine" the use of the results to support the need for an ECAM. Do you agree?

A. No. I believe the stochastic study, which has had no meritorious rebuttal, provides compelling evidence to support the need for an ECAM.

Q. Does Mr. Chernick address your load examples?

A. Yes. He spends several pages addressing the two hourly examples that were provided in my Supplemental direct testimony to try to determine if the Company made money or lost money in those particular hours. His analysis misses the point. The point of the load examples was to show that actual loads can vary significantly from forecast loads, even when the forecast is only two to three months old.

Q. Does Mr. Chernick agree that load forecasts are inherently wrong?

A. Yes. He states that "it seems obvious that any forecast of the loads on particular hours conducted more than a few days in advance will be wrong." (Chernick at 294)

Q. What does Mr. Chernick recommend to address the volatility of load forecasts?

A. He suggests that the Company has not been doing a good job of forecasting a realistic pattern of high and low loads for estimating net power costs and recommends that the Company should improve its load modeling for net power costs.

Q. Has the OCS reviewed the Company's load forecasting methodology?

A. Yes. The Company's load forecasting methodology was independently reviewed by OCS's consultant from GDS Associates, Atlanta, Georgia who concluded that "the methodology and models currently used by PacifiCorp meet or exceed industry standards."[3] This review was conducted in 2009.

Q. What do you conclude from this?

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[3] Evaluation of PacifiCorp's Load Forecast, June 17, 2009, GDS Associates (page 1, Section 1.1.1), Docket No. 09-2035-01 (June 18, 2009).

A. Replacing the load forecasting model cannot eliminate the volatility of retail load estimates and the need for an ECAM.

Q. Does Mr. Chernick address wind variability?

A. Mr. Chernick concludes that when actual wind production is below what is included in the net power costs study, then net power costs will increase and vice versa. He did not rebut the fact that the Company has recently added about 1,400 MW of new wind resources to its portfolio greatly increasing its exposure to the volatility of wind generation, nor that wind is unpredictable.

Q. Do any witnesses address hydro variability?

A. Yes. Mr. Chernick states that hydro variability is not very relevant because the Revised Protocol is designed to take away from Utah most of the benefits of the Company's hydro resources. (Chernick at 580) Mr. Higgins states that placing hydro-related risk on Utah customers is not appropriate because Utah does not receive a proportionate benefit from the PacifiCorp hydro resources. (Higgins at 380)

Q. Are the claims of Messrs. Chernick and Higgins valid?

A. No, not when Utah rates are determined using rolled-in plus a cap as has been the case for the last four rate cases. If Utah rates were set directly using the Revised Protocol methodology, I would partially agree with Messrs. Chernick and Higgins. In that case, Utah would receive a proportionate share of the benefits of the Bear River generation and other east side hydro generation, but would not receive the benefits of hydro generation on the west side of the Company's system. However, since rates have been set using rolled-in plus a cap under the

Revised Protocol method for the past four years, Messrs. Chernick and Higgins are wrong.

Incentives

Q. OCS, the Division, UAE and WRA all indicate that one of the risks of an ECAM is that it reduces the Company's incentive to plan and operate the system in the least cost manner. How do you respond to these concerns?

A. I believe incentives are manageable, and far under shadow the risk and consequences of forecast variance identified earlier in my testimony.

Q. Why do you believe these concerns are manageable?

A. The Commission has a number of safeguards in place to protect against the unlikely event that there are inefficient actions by the Company. First, Utah has a robust integrated resource planning and resource procurement process that is transparent and actively monitored by Utah parties and the Utah Commission. Second, the recent legislative changes allowing single-item rate cases for major capital additions put wind plants, gas-fired plants and purchased power contracts on equal footing from a rate recovery perspective, because the Company would have an opportunity to recover the costs of the new resources through a single-item rate case in addition to including the costs and generation of the new resources in net power costs. This change has eliminated any potential bias the Company could have towards purchased power. Finally, the ECAM is not proposed as an automatic pass-through mechanism; rather, parties and the Commission will have the ability to audit actual results to ensure that only prudent costs flow through the ECAM. The specific mechanisms to protect customers from paying for imprudent costs will be specified in Phase II of this proceeding.

Q. Some parties have expressed concern that auditing actual net power costs would increase the workload on the Commission and other Utah parties? How do you respond?

A. The Division of Public Utilities reviews the Company's results of operations in general rate cases or through formal audits of the semi-annual reports filed with the Commission. Workload under RMP's proposed ECAM should be reduced because the auditing work is already being conducted and the modeling and forecasting workload will decrease. In any case, the role of the Commission and Division is to regulate public utilities in the public interest. Where the public interest is served by a change in regulatory approach that more accurately reflects the actual cost of service in customer prices, any possible increase in workload is justified.

Dependence on Market Energy

Q. Ms. Beck raises a concern that the Company is too dependent on market energy and recommends the Commission must resolve this issue before any ECAM could be found to be in the public interest. Ms. Kelly also raised similar concerns. Are these concerns valid?

A. No. The last IRP that was acknowledged by the Commission was the 2004 IRP. That plan included 1,100 to 1,200 megawatt of market purchases – otherwise known as Front Office Transactions – in each year of the plan. The Company's most recent plan, the 2008 Integrated Resource Plan is reasonably consistent with the last direction the Commission provided the Company on this issue as shown in Table 1 below.

Table 1

	2009	2010	2011	2012	2013	2014	2015
2004 Integrated Resource Plan (January 2005)							
East	700	700	700	700	700	700	700
West	400	400	400	500	500	500	500
TOTAL	**1,100**	**1,100**	**1,100**	**1,200**	**1,200**	**1,200**	**1,200**
2008 Integrated Resource Plan (May 2009)							
East	75	50	150	394	493	200	202
West	0	0	59	839	839	739	739
TOTAL	**75**	**50**	**209**	**1,233**	**1,332**	**939**	**941**

Q. How much of PacifiCorp's firm load obligations are planned to be met with uncommitted market purchases?

A. Through 2016, the Company plans to meet 10 percent or less of its firm load obligations with uncommitted market purchases. This is shown in Table 5.18 on page 91 of the 2008 Integrated Resource Plan. A copy of Table 5.18 is provided as Exhibit RMP___(GND-3R). As can be seen on the last line of Exhibit RMP___(GND-3R), the "Reserve Margin" for 2016 is -10 percent, meaning that 90 percent of the firm obligation is planned to be met with committed resources. In 2012, only four percent of the Company's firm obligations are planned to be met with uncommitted market purchases.

Q. What do you conclude from this?

A. There is no valid reason for the Commission to delay implementation of an ECAM pending an investigation into the Company's reliance on market energy. Ms. Beck's recommendation is discriminatory and amounts to no more than a double standard: one standard if net power costs are estimated using a computer model, and a second but higher standard if net power costs are recovered through an ECAM. The Company believes that the integrated resource planning process is the proper forum to consider the issue of the level of reliance on market energy. It is our understanding that the Commission is currently considering the 2008 IRP at this time and may issue an order on that plan in the future and that the OCS has voiced its concerns to the Commission through comments in that docket. As Dr. McDermott testified in his Supplemental direct testimony, once the mix of resources is determined in the integrated resource planning process, an ECAM is appropriate to deal with the volatility and lack of management control of net power costs incurred using that mix of resources.

Earnings Impact of ECAM

Q. Do you agree with Mr. Peterson's analysis showing the Company would have earned above its authorized cost of equity had the proposed ECAM been in effect?

A. No. The Company does not agree with certain assumptions in Mr. Peterson's pro forma calculation of return on equity.

Q. Please explain.

A. First, Mr. Peterson relies on the Securities and Exchange Commission (SEC) financial reports to compute a return that he compares to the return on equity approved by the Commission in the Company's general rate cases. SEC reporting does not translate directly to the Company's regulated results of operations filed in its earnings reports to the Commission and used to set rates in general rate cases, and SEC reported income does not equal income for regulated results of operations. The more appropriate financial results to use in Mr. Peterson's analysis would be the Company's regulated results of operations allocated to Utah and filed semi annually with the Commission.

Second, Mr. Peterson erroneously assumes that the system under collection of net power costs reported in Table 1 of my Supplemental direct testimony would be recovered in its entirety and added to the Company's income for the respective periods if an ECAM had been in place in Utah. The recovery shortfall demonstrated in my testimony was indeed a comparison of the total Company net power costs reflected in Utah customers' rates versus the actual total Company net power costs experienced by the Company. However, rates set either through a general rate case or an ECAM mechanism in Utah will only be set to cover the level of net power costs allocated to Utah; neither of these avenues for cost recovery in Utah will allow the Company to recover the entire shortfall on a total Company basis. Differing regulatory policies and ratemaking mechanisms among the states served by PacifiCorp cause each state to have different "total Company" net power costs in rates at a given time and differing levels of net power cost recovery by jurisdiction. In addition, Mr. Peterson's application of the reported total Company shortfall to historical total Company earnings double counted recovery of a portion of the net power cost recovery shortfall if jurisdictional differences are considered.

In response to DPU data request 4.3, the Company provided an analysis of what would have happened had the ECAM been in place from 2002 through 2008.[4] While my table reported total Company NPC under recovery of $161.8 million in

[4] Mr. Peterson included the portion of this analysis pertaining to 2008 in his Exhibit 1.3.

2007 and $230.2 million in 2008, the analysis in DPU 4.3 demonstrates that the Company's proposed ECAM would have deferred $55.5 million and $76.5 million of the total Company shortfall in 2007 and 2008, respectively, for later recovery through rates set in Utah.

Since an ECAM recovers only actual net power costs, it does not allow recovery in excess of actual net power costs; therefore, an ECAM by itself cannot result in earnings above the authorized rate of return.

Q. Does this conclude your testimony?

A. Yes.