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

A. My name is Brian S. Dickman. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

Qualifications

Q. Briefly describe your education and business experience.

A. I received a Master of Business Administration from the University of Utah with an emphasis in finance and a Bachelor of Science degree in accounting from Utah State University. Prior to joining the Company, I was employed as an analyst for Duke Energy Trading and Marketing. I have been employed by the Company since 2003 including positions in revenue requirement and regulatory affairs, and I assumed my current role managing the Company's net power cost group in March 2012.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the Idaho Public Utilities Commission, the Wyoming Public Service Commission, and the Utah Public Service Commission.

Purpose of Testimony

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

A. My testimony presents the Company's calculation of the Energy Balancing Account ("EBA") deferral amount for the three month period from October 1, 2011, through December 31, 2011 ("Deferral Period"). More specifically, I provide the following:

- Details of the calculation of the EBA deferral amount of $9.1 million using the all-party stipulated methodology ("Stipulated Scalar") approved by the Commission in its September 13, 2011, order resolving Docket No. 10-035-124, et al. ("2011 Stipulation"), and the additional costs making up the $29.3 million requested EBA recovery; and,
- An overall discussion and quantification of the main drivers of the difference between actual net power costs ("Actual NPC") and net power costs in rates ("Base NPC").

Q. Are additional witnesses presenting testimony in this case?

A. Yes. Mr. Steven R. McDougal, Director of Revenue Requirement, is sponsoring testimony discussing the background of the EBA and supporting the allocation of net power costs to Utah in the EBA. Mr. William R. Griffith, Vice President Regulation, is sponsoring testimony regarding the rate spread and rate design of the EBA surcharge.

Summary of the EBA Deferral Calculation

Q. Please describe the Company's calculation of the EBA deferral for the Deferral Period.

A. The Company calculated a total EBA deferral of $9,003,977 over the Deferral Period, plus $53,320 of accrued interest for a total of $9,057,297. Exhibit RMP___(BSD-1) presents a detailed review of the Company's monthly calculation of the EBA deferral.

The Company's request also includes two additional items: 1) interest in the amount of $228,708 that will accrue on the EBA Deferral Account Balance prior to the EBA Rate Effective Date of June 1, 2012, and 2) an incremental $20 million surcharge agreed to in the 2011 Stipulation that represents the first year of a three-year amortization of NPC previously deferred on the Company's books prior to September 20, 2011. Table 1 below provides a detailed breakdown of the total requested EBA recovery.

Table 1
Summary of EBA Deferral Account Balance

Incremental EBA Deferral		
Actual EBA Rate ($/MWh)		23.50
Base EBA Rate ($/MWh)		21.39
$/MWh Differential	$	2.11
Utah Load (MWh)		6,103,728
Total Deferrable	$	12,862,824
EBA Deferral at 70% Sharing	**$**	**9,003,977**
EBA Deferral Account Balance		
Beginning EBA Deferral Balance: Oct 1, 2011		**-**
Incremental EBA Deferral		9,003,977
Interest		53,320
EBA Revenues		-
Ending EBA Deferral Balance: Dec. 31, 2011	**$**	**9,057,297**
Accrued Interest through June 1, 2012		228,708
Stipulated Deferred Net Power Costs Amortization		20,000,000
Requested EBA Recovery	**$**	**29,286,005**

Q. What revenue requirement components are included in the EBA deferral calculation?

A. The EBA deferral calculation consists of two revenue requirement components: NPC and wheeling revenue. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue. Wheeling revenue includes amounts booked to the Federal Energy Regulatory Commission ("FERC") account 456.1, Revenues from transmission of electricity of others. Collectively these two components are known in the Company's proposed EBA tariff as Energy Balancing Account Costs ("EBAC").

Q. What methodology did the Company use to calculate the EBA Deferral Account Balance?

A. The EBA calculation is a comparison of actual NPC and wheeling revenue to the levels in rates as established in a general rate case, with 70 percent of the difference being deferred for later recovery or refund to customers. The calculation of the monthly amount debited or credited into the EBA Deferral Account is based on the following formula:

$$EBA\ Deferral_{\ Utah,month} =$$

$$\left[\left(Actual\ EBAC_{\frac{month}{MWh}} - \ Base\ EBAC_{\ \frac{month}{MWh}}\right) \times \ Actual\ MWh_{Utah,month}\right] \text{ x } 70\%$$

The calculation of the Actual EBAC, Base EBAC, and the resulting EBA Deferral in this application is according to the Stipulated Scalar methodology developed and approved in the 2011 Stipulation.

Consistent with the Commission's order approving the 2011 Stipulation, the Company has also calculated the amount that would have resulted from using the EBA formula detailed in the Commission's March 3, 2011, Corrected Report and Order in Docket No. 09-035-15. This calculation is provided for informational purposes in Exhibit RMP___(BSD-2). The testimony of Mr. McDougal discusses the different approaches used in each method of computing Utah-allocated NPC for the EBA.

Q. On a total Company basis, what was the difference between Actual NPC and Base NPC for the Deferral Period?

A. On a total Company basis, Actual NPC for the Deferral Period were approximately $367 million, or approximately $22 million higher than the $345 million Base NPC from the 2011 Stipulation. Table 2 below summarizes the differences between Actual NPC and Base NPC.

Table 2
Total Company Net Power Cost Reconciliation ($millions)

			EBA Deferral Period
1	Base NPC (2011 Stipulation)	$	344.9
2	Settlement Adjustment		7.8
3	2011 GRC Rebuttal NPC		352.7
4	Increase/(Decrease) to NPC:		
5	Wholesale Sales Revenue		39.3
6	Purchased Power Expense		37.2
7	Coal Fuel Expense		(19.7)
8	Natural Gas Fuel Expense		(41.4)
9	Wheeling, Hydro and Other Expense		(1.0)
10	Actual NPC	$	367.1
11	Total Increase / (Decrease) to NPC	$	22.1

Q. Please describe Table 2 and the line items making up the difference between Actual NPC and Base NPC.

A. Line one of Table 2 shows the settled level of NPC, or the approved Base NPC, for the three months of the Deferral Period. Line two of Table 2 shows the settlement adjustment of approximately $7.8 million (out of the total $33.4 million stipulated reduction to NPC included in the 2011 Stipulation) that was applicable to the Deferral Period. The remainder of Table 2 is a breakout of the difference between Actual NPC and Base NPC (after removing the settlement adjustment) by cost category on a total Company basis. Because the settlement adjustment in the 2011 Stipulation was not identified by category, an item by item comparison of Actual NPC to the stipulated NPC is not possible. The differences by category in Table 2 result from comparing Actual NPC to the rebuttal NPC in the 2011 GRC.

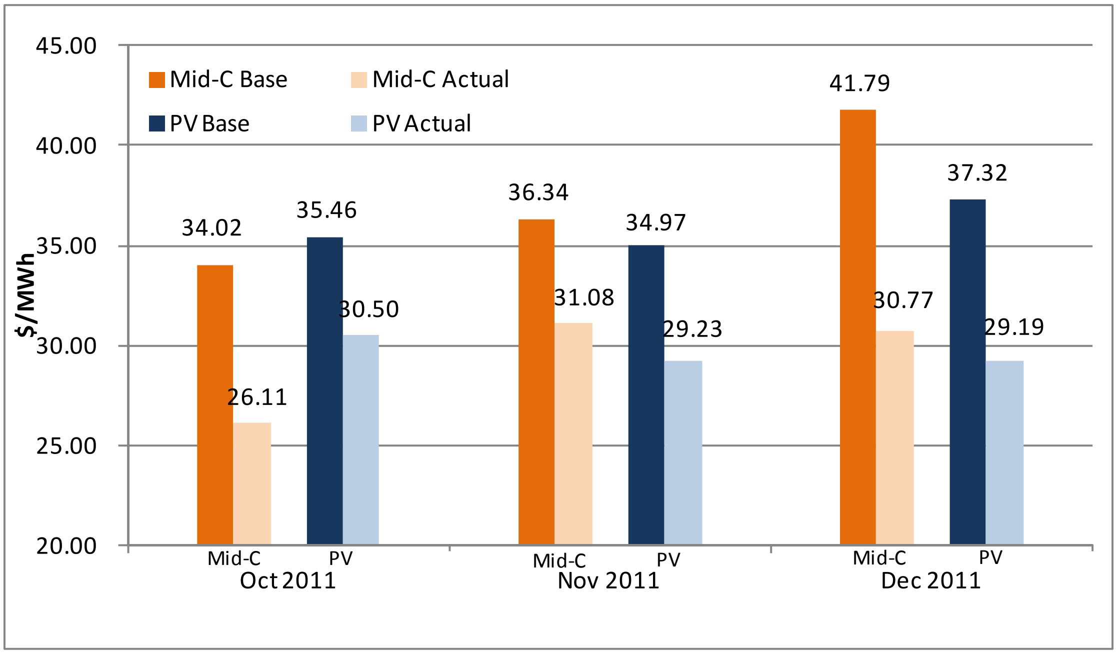
Principle Drivers of NPC Variance

Q. What is the principle driver causing Actual NPC to be different from Base NPC?

A. The principle driver of the difference in NPC was the decline in wholesale electricity and natural gas market prices as compared to the prices reflected in the 2011 Stipulation. The change to wholesale market prices resulted in a re-optimization of the Company's supply portfolio to achieve the lowest NPC for customers. The lower market prices resulted in reduced coal and natural gas generation volumes, which in return resulted in reduced wholesale sales and increased purchased power volumes.

Wholesale electricity market prices declined by approximately 20 percent and natural gas prices fell by approximately 26 percent compared to the March 31, 2011, Official Forward Price Curve ("OFPC") reflected in Base NPC. Table 3 below demonstrates the magnitude of the change using the Mid-Columbia ("Mid-C") and Palo Verde ("PV") average wholesale electricity market price reflected in Base NPC versus actual average wholesale electricity market prices at the respective trading hubs.

Table 3



Q. How do lower wholesale electricity market prices change the volume of wholesale sales the Company makes during the Deferral Period?

A. In general, lower wholesale electricity market prices impact the economics of the Company's coal and natural gas units, such that, if wholesale electricity market prices are less than the cost of generating electricity at Company facilities the Company will not operate those facilities. In this circumstance, the Company will purchase lower cost power to serve customers, or, if customer load has already been served, the Company will back down the uneconomic facility as it cannot make an economic sale of excess generation. For the Deferral Period the drop in wholesale electricity market prices caused a reduction in wholesale sales revenues of approximately $39.3 million as shown in Table 2. Total wholesale sales volume decreased 961 gigawatt-hours ("GWh"), or nearly 25 percent compared to the volume included in Base NPC. On the other hand, lower market prices allowed the Company to acquire more economic market purchases at a cost that was lower than the cost to generate, which contributed to a corresponding increase of $37.2 million and 647 GWh in purchased power expense compared to the amount in Base NPC. The loss in wholesale sales revenue and increase in purchased power costs were offset, in part, by reduced coal and natural gas fuel expense of $19.7 million and $41.4 million respectively.

Q. Please further describe the changes in coal fuel expense and the decrease in volume compared to Base NPC.

A. The decrease in coal fuel expense of approximately $19.7 million is due to the decrease in volume of the Company's coal generation facilities of 1,266 GWh compared to Base NPC. The average cost per MWh of coal fuel expense stayed relatively flat, increasing by only $0.14 per MWh or less than 1 percent.

Q. Did any other factor, in addition to the change in wholesale electricity prices, impact the volume of actual coal generation compared to the amount included in Base NPC?

A. Yes. The reduction in the volume of coal generation in this case is partly driven by differences in normalized versus actual planned outages. To compute Base NPC in a general rate case, the Company applies a four-year average outage rate to its coal units to normalize output in a given test period. This approach produces normalized coal generation consistent with the Company's practice of overhauling units on a four-year cycle, but it will not match actual experience during a short period of time. For example, during the Deferral Period both Huntington 2 and Naughton 2 were on planned outage for more than a month. The

Company's normalized study included a shorter planned outage at Huntington 2 and no planned outage at Naughton 2 during the Deferral Period.

Q. Please further describe the changes in natural gas fuel expense and the decrease in volume compared to Base NPC.

A. The total natural gas fuel expense in Actual NPC decreased by $41 million compared to Base NPC. The decrease in natural gas fuel expense was due to the decrease in generation of the Company's natural gas facilities of 737 GWh.

Q. Why did generation at the Company's natural gas facilities decrease when the average market price for natural gas decreased at a faster rate than the average market price for electricity?

A. The comparison of average market prices for electricity and natural gas may seem to indicate that generation at the Company's natural gas facilities would be more economical. However, when viewed at a more granular level, i.e. hourly prices and specific market hubs, there were still many times during the Deferral Period when the market price of electricity was lower than the cost of generation at the Company's natural gas plants. Consequently, generation volumes at many of the Company's natural gas generating facilities were lower than the amount included in Base NPC.

Q. Did the Company include the settled value of its natural gas and power hedges, both physical and financial, in its Actual NPC and EBA deferral calculation?

A. Yes. Consistent with the Commission order approving the 2011 Stipulation, the Company included all settled gains and losses of its natural gas and power hedges (i.e. swaps) in the EBA deferral calculation.[1]

Q. Have you provided detailed work papers supporting the tables and exhibits in your testimony?

A. Yes. Exhibit RMP___(BSD-3) contains an index to my work papers, which are provided on a compact disc ("CD") with the Company's filing. These work papers are generally consistent with the information provided to the Division of Public Utilities ("DPU") in response to data request DPU 1.1 in the EBA tariff proceeding, Docket No. 11-035-T10. Additional information is also provided on the CD accompanying the Company's application that is consistent with the filling requirements proposed in the DPU's EBA Pilot Program Evaluation Plan filed with the Commission in Docket No. 09-035-15.

Q. Does this conclude your direct testimony?

A. Yes.

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[1]The Commission's Corrected Report and Order dated March 3, 2011 in Docket No. 09-035-15 was later modified by the Report and Order approving the 2011 Stipulation, wherein the Commission vacated its prior position regarding swaps in the EBA calculation.