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

A. My name is C. Craig Paice. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon 97232. I am currently employed as a Regulatory Consultant in the Regulation Department.

**Qualifications**

**Q. Please briefly describe your education and business experience.**

A. I received a Bachelor of Science Degree in Business Management from Brigham Young University in 1976. I have also attended various educational, professional and electric industry seminars during my career with the Company. I have been employed by PacifiCorp since the merger in 1989. Prior to that time, I was employed with Utah Power & Light Company beginning in 1978 holding various positions in the accounting, customer service, and regulatory areas.

**Q. Please describe your present duties.**

A. My primary responsibilities are to prepare, present, and explain the results of the Company's cost of service studies to regulators and interested parties in jurisdictions where PacifiCorp provides retail electric service.

**Q. Have you been a witness in other regulatory proceedings?**

A. I have previously provided cost of service testimony in the states of Utah, Wyoming, Idaho, Oregon, Washington, and California.

**Purpose of Testimony**

**Q. What is the purpose of your testimony?**

A. I will present the Company's functionalized Class Cost of Service Study based on the 12 month forecasted test period ending June 30, 2012.

**Summary of Results**

**Q. Please identify Exhibit RMP___(CCP-1) and explain what it shows.**

A. Exhibit RMP___(CCP-1) is the summary table from PacifiCorp's 12 Months Ending June 2012 Class Cost of Service Study for the State of Utah. It is based on PacifiCorp's annual results of operations for the State of Utah as presented in the testimony of Mr. Steven R. McDougal. It summarizes, both by customer group and by function, the results of the cost study for the 12 months ending June 2012. Page 1 presents the results at the Company's June 2012 Rate of Return assuming current rate levels. Page 2 shows the results using the return provided by the $232.4 million revised protocol rate mitigation premium increase.

**Q. Please identify Exhibit RMP___(CCP-2) and explain what it shows.**

A. Exhibit RMP___(CCP-2) shows the cost of service results in more detail by class and by function. Page 1 summarizes the total cost of service summary by class and pages 2 through 6 contain a summary by class for each major function.

**Changes in Cost of Service Study**

**Q. Are there any differences between this cost of service (COS) study and the study filed with the Utah Commission in Docket No. 09-035-23?**

A. Yes. Several modifications were made to the COS study to comply with the Commission's order in Phase I of Docket No. 09-035-23. First, income taxes are calculated for each customer class based on taxable income instead of rate base. Next, the Commission acknowledged that there were inconsistencies between the allocation factors used in the jurisdictional allocation model (JAM) and the class cost of service model. They directed a work group be convened to review, update and revise these allocation issues. Although work group parties did not reach consensus, the Company identified and revised various functional and COS allocation factors to address consistency concerns. The revised factors used in the COS study are listed by FERC account in Exhibit RMP___(CCP-4).

**Q. Given the Commission's concerns with consistency between the JAM and COS study, why does the Company continue to seasonally weight generation and transmission fixed costs and allocate Net Power Costs (NPC) on a monthly basis as it did in Docket No. 09-035-23?**

A. The seasonal weighting of generation and transmission fixed costs and monthly allocation of NPC was first introduced by Company witness Mr. David L. Taylor in Docket No. 06-035-21 and has been used in every COS study presented since that time. These methodology revisions were the Company's response to the 2005 Utah COS Taskforce's general consensus that a cost of service methodology better reflecting seasonal and time differentiated load and cost differences be explored. As such, the Company continues to employ these methodologies in the COS study.

**Q. Did the Commission address the classification and allocation of generation and transmission costs in its order in Docket No. 09-035-23?**

A. Yes. The Commission's order in Docket No. 09-035-23 stated the following on page 123:

> "We find the Company's classification and allocation methods for generation and transmission costs are generally consistent with our prior decisions."

As such, the Company believes the methods currently used in the COS study to classify and allocate generation and transmission fixed costs in the state of Utah are appropriate.

**Classification of Wind Generation Costs**

**Q. In Docket No. 09-035-23, what direction did the Commission provide regarding the classification of wind generation costs?**

A. The Commission stated that the Company should separately identify wind resources in its accounting system. These costs have been identified within various accounts in the JAM and are allocated using the SG factor. They are included in the cost study in the appropriate accounts and allocated to customer classes using the same system coincident peak allocation factor (F10) used to allocate all demand-related generation resources.

**Treatment of the Rate Mitigation Cap**

**Q. Was the cost of service study modified to address the Commission's direction in Docket No. 09-035-23 regarding treatment of the rate mitigation cap under the Roll-In method?**

A. No. This change was not necessary because the revenue requirement used in the COS study was not based on the Roll-In method multiplied by a rate mitigation cap. The revenue requirement employed is the Revised Protocol method multiplied by a rate mitigation premium.

**Description of Procedures**

**Q. Please explain how the Cost of Service Study was developed.**

A. Based on the results from Mr. McDougal's Exhibit RMP___(SRM-3), the COS study employs a three-step process referred to as functionalization, classification, and allocation. These three steps recognize the way a utility provides electrical service and assigns cost responsibility to the groups of customers for whom those costs were incurred.

**Q. Please describe functionalization and how it is employed in the Cost of Service Study.**

A. Functionalization is the process of separating expenses and rate base items according to five utility functions - production, transmission, distribution, retail and miscellaneous.

- The production function consists of the costs associated with power generation, including coal mining, and wholesale purchases.
- The transmission function includes the costs associated with the high voltage system utilized for the bulk transmission of power from the generation source and interconnected utilities to the load centers.
- The distribution function includes the costs associated with all the facilities that are necessary to connect individual customers to the transmission system. This includes distribution substations, poles and wires, line transformers, service drops and meters.
- The retail services function includes the costs of meter reading, billing, collections and customer service.
- The miscellaneous function includes costs associated with Demand Side Management, franchise taxes, regulatory expenses, and other miscellaneous expenses.

**Q. Describe classification and explain how it is used by the Company in the COS study.**

A. Classification identifies the component of utility service being provided. The Company provides and customers purchase service that includes at least three different components: demand-related, energy-related, and customer-related. Demand-related costs are incurred by the Company to meet the maximum demand imposed on generating units, transmission lines, and distribution facilities. Energy-related costs vary with the output of a kWh of electricity. Customer-related costs are driven by the number of customers served.

**Q. How does PacifiCorp determine cost responsibility between customer groups?**

A. After the costs have been functionalized and classified, the next step is to allocate them among the customer classes. This is achieved by the use of allocation factors that specify each class' share of a particular cost driver such as system peak demand, energy consumed, or number of customers. The appropriate allocation factor is then applied to the respective cost element to determine each class' share of cost. A detailed description of PacifiCorp's functionalization, classification and allocation procedures and the supporting calculations for the allocation factors are contained in my workpapers.

**Q. How are generation and transmission fixed costs apportioned among customer classes?**

A. The Company classifies production and transmission fixed costs as 75 percent demand and 25 percent energy with the demand component of Factor 10 developed using 12 monthly weighted coincident peak demands. In lieu of all 12 monthly load values receiving an equal weight, each monthly value is assigned a different weighting factor. Monthly weighting factors are calculated by dividing each month's system coincident retail peak by the annual system retail peak. For the 12 months ending June 2012, the system retail peak is forecasted to be 9,999 MW during July 2011. The month of July receives a weighting of 1.00 (9,999/9,999). The forecasted system retail peak in January 2012 is forecasted to be 8,984 MW, therefore it receives a weighting of 0.8985 (8,984/9,999). The 12 monthly class coincident peaks are multiplied by the monthly weighting factors and summed to calculate the demand allocation factor. This methodology was first introduced in Docket No. 06-035-21.

**Q. Are the factors used to allocate Net Power Costs (NPC) calculated the same as those used in Docket No. 09-035-23?**

A. Yes. Since monthly class coincident peak and energy loads are included in the Cost of Service Study and Net Power Costs are calculated and summarized by month in the NPC study, PacifiCorp recommends that fuel and other NPC components be allocated on a monthly basis. Factors F85 through F96 are used in the Cost of Service Study to allocate monthly net power costs. A description of factor development is contained in Exhibit RMP___(CCP-3).

**Q. How are distribution costs allocated?**

A. Distribution costs are classified as either demand related or customer related. In this study, only meters and services are considered as customer related with all other costs considered demand related. Distribution substations and primary lines are allocated using the weighted monthly coincident distribution peaks. Distribution line transformers and secondary lines are allocated using the weighted non-coincidental peak method. Meter costs are allocated to all customers. The meter allocation factor is developed using the installed costs of new metering equipment for different types of customers.

**Q. How are services costs allocated to customers?**

A. Services costs continue to be allocated to secondary voltage delivery customers using an allocation factor based on the installed cost of new services for different customer types. The cost of new services reflects the Company's current method of allocating service costs assuming a single service drop per average customer regardless of class. This methodology is used since Company records do not contain data regarding the number of customers per service drop.

**Q. Are there concerns with how services drop costs are allocated in the cost of service study?**

A. Yes. The Commission's order in Docket No. 09-035-23 directed the Division of Public Utilities (Division) to conduct a comprehensive analysis regarding the Company's current method of allocating service drop costs and recommend alternatives. The status of the Division's investigation remains undetermined at this time.

**Q. Please explain how customer accounting, customer service, and sales expenses are allocated.**

A. Customer accounting expenses are allocated to classes using weighted customer factors. The weightings reflect the resources required to perform such activities as meter reading, billing, and collections for different types of customers. Customer service expenses are allocated on the number of customers in each class.

**Q. How are administrative & general expenses, general plant and intangible plant allocated by PacifiCorp?**

A. Most general plant, intangible plant, and administrative and general expenses are functionalized and allocated to classes based on generation, transmission, and distribution plant. Employee pensions and benefits have been assigned to functions and classes on the same basis as labor costs. Costs that have been identified as supporting customer systems are considered part of the retail services function and have been allocated using customer factors. Coal mine plant costs are allocated using the energy factor.

**Q. How are costs and revenues associated with wholesale contracts and other electric revenues treated in the Cost of Service Study?**

A. No costs are assigned to wholesale contracts and other electric revenues. The revenues from these transactions are treated as revenue credits and are allocated to customer groups using the appropriate allocation factors. Revenue credits reduce the revenue requirement that is to be collected from firm retail customers. This is consistent with the treatment of these revenues in the inter-jurisdictional results of operations.

**Special Contracts**

**Q. Have you included cost of service results for the Utah special contracts?**

A. Yes. Consistent with both the treatment in the last case and the Revised Protocol, the loads and revenues associated with service to special contract customers are included as part of the jurisdictional allocation and included in the revenue requirement. The loads and revenues for special contract customers are also included in the Cost of Service Study.

**Partial Requirements/Back-up/Electric Furnace Service**

**Q. Does the Cost of Service Study include results for partial requirements, back-up service and electric furnace customers?**

A. No. Cost of service results were not calculated for these categories of customers, which includes one special contract customer and those customers taking service on Schedule 21 and Schedule 31.

**Q. Why are these customers removed from the Cost of Service Study?**

A. Partial requirements, back-up service and electric furnace customers are not included in the embedded Cost of Service Study because they do not lend themselves well to this type of analysis. These customers usually have very sporadic loads from year-to-year producing volatile cost of service results depending on whether or not service is required during the hour of monthly system peak. It is the Company's practice to derive prices for partial requirements and back-up service from the prices and costs for full requirements service.

**Marginal Cost of Service Study**

**Q. Why is the Company providing a Utah marginal cost of service study in this proceeding?**

A. The Company prepared a Utah marginal cost of service study to comply with the Commission's Phase II order on Rate Design in Docket No. 09-035-23. These results are provided for informational purposes only.

**Q. Please describe the marginal cost of service study.**

A. The marginal cost study shows, by customer class, the Company's marginal cost of resources required to produce one additional unit of electricity, or to add one additional customer. The study contains seven summary tables followed by seventeen sections of supporting data.

**Q. How are marginal costs calculated?**

A. One-year marginal costs include only changes in operating costs while 10 and 20 year marginal costs also include the cost of expanding facilities. The costs of these added facilities results in long-run costs that are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. They do not include any demand-related generation, transmission or distribution costs.

**Q. Please describe the marginal cost summary tables.**

A. Tables 1 and 2 summarize the one, 10, and 20-year marginal costs on a mills per kWh or dollars per customer basis. Table 3 summarizes the unit costs based on the results of the long-run (20-year) marginal cost study. Unit costs are shown for generation, transmission, distribution and various customer service functional categories. Table 3 also includes energy usage, peak demand and number of customers by customer class for the 12-months ending June 30, 2012. This information is used to calculate annual long-run marginal costs by class shown on Table 4.

. Table 5 summarizes embedded revenue requirements for each function at the target level. On Table 6, the total embedded revenue requirement for the state of Utah is reduced by the proposed revenues for those classes which are excluded from the marginal cost of service study (partial requirements, electric furnace, and lighting that is closed to new service) and by AGA revenue. Embedded revenue requirement for each function is then reduced proportionately and shown on line 5. Table 7 shows full marginal cost of service by function and class. The values in Columns B through M are divided by the total in Column A to develop allocation percentages for each class by function. Production, Transmission, Distribution, and Retail function percentages by class are based upon full marginal costs. Miscellaneous function percentages by class are based upon share of total MWh sales. The embedded revenue requirement is then reduced for excluded revenues from Table 6 and spread to the classes based upon the functional allocation factors and summed to produce the target revenue requirements by class. Present operating revenues are deducted from the total revenue requirements to calculate the dollar and percentage change required to achieve full cost of service for each class.

**Q. Please explain how generation marginal costs are calculated.**

A. The marginal generation costs in this study are based on the Company's most recently approved Utah avoided cost calculations from Docket No. 10-035-T07. New resource costs are based on the fixed and variable cost of a combined cycle combustion turbine, which operates as a base load unit. Recognizing that base load generation produces the dual products of capacity and energy, capacity costs are determined using the fixed costs of a simple cycle combustion turbine. The remaining fixed and all variable costs of the combined cycle turbine are considered energy related. Marginal generation costs are summarized on Table 8.

**Q. Please explain how are transmission costs calculated?**

A. Transmission costs are based on a five-year analysis of forecasted expenditures to meet increased load on the transmission system. Expenditures identified as growth-related are used to develop marginal transmission costs. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand. Bulk power lines are classified both to demand and energy in the same proportions as the long-run marginal costs of generation resources. Marginal transmission costs are summarized on Table 9.

**Q. Please provide a general overview of how marginal distribution costs are determined.**

A. Table 10 provides a unit cost summary by class and load size of marginal distribution costs. Distribution costs are classified into three components: (1) Demand-related, shown in dollars per kW/year; (2) Commitment-related, shown in dollars per customer/year; and (3) Billing-related, shown in dollars per customer/year. Commitment-related distribution costs consist of the costs of transformers, poles and conductors that are not determined by the level of demand customers place on the system. Demand-related distribution costs include additional costs of larger transformers, substations, poles and conductors with sufficient capacity to serve the level of demand a customer class places on the system.

**Q. Please describe how are substation marginal costs calculated?**

A. Marginal substation costs are determined using the per kW cost of substation additions being considered for a five-year period. The cost per kW is determined by dividing the growth related distribution substation investment in the capital budget horizon by the related increase in substation capacity. Substation marginal costs are classified entirely to demand and are allocated to customer classes based on the distribution peak load for each class.

**Q. Please describe how the marginal costs of distribution circuits are calculated.**

A. Marginal costs of distribution poles and wires are calculated using the Company's Distribution Circuit Model. The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics and current cost estimates for the State of Utah. Customer locations are based on actual customer distances from the substation as determined by the Company's Computer Aided Design Operations (CADOPS) database. The results are segregated into commitment-related and demand-related costs for each customer class.

**Q. Please describe how the marginal costs of distribution line transformers are calculated.**

A. Marginal commitment and demand transformer costs are calculated using a least squares regression analysis of installed cost versus size of the Company's commonly installed transformers. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

**Q. Please identify the costs included in the service drop category?**

A. The service drop category includes the marginal cost of service drops with associated operation and maintenance costs (O&M). Current typical installed costs for service drops are determined for each customer load size.

**Q. What is included in the metering category?**

A. The metering category includes the marginal cost of metering equipment with associated O&M and meter reading expense. Typical installed metering costs are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Meter O&M is based on historical expenditures.

**Q. What is included in the billing and customer service/other categories?**

A. This category includes the costs of billing, payment processing and debt recovery, meter reading expense and all the remaining customer accounting and customer service activities. Meter reading expense is based on historical costs and allocated to customer classes based on typical meter reading costs. Customer accounting and customer service expense are based on historical expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities.

**Workpapers**

**Q. Have you included your workpapers?**

A. Yes. Workpapers showing the complete functionalized results of operations and embedded class cost of service detail are included as Exhibit RMP___(CCP-3). Also included is a detailed narrative describing the Company's functionalization, classification and allocation procedures. The marginal cost of service study is provided as Exhibit RMP___(CCP-5), portions of which are confidential.

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

A. Yes, it does.