BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations	**)))))))))**	**<u>Docket No. 09-035-23</u>** **<u>DPU Exhibit No. 5.0R</u>**

Rebuttal Testimony of

Joseph Mancinelli
Witness 5.0R

For the Division of Public Utilities

Department of Commerce

State of Utah

November 12, 2009

I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Joseph Mancinelli. I am employed by R. W. Beck as Vice President of the Management and Economic Consulting practice.

Q. Have you submitted Direct Testimony in this proceeding?

A. Yes. I submitted Direct Testimony on October 8, 2009.

Q. What is the purpose of your Rebuttal Testimony?

A. My rebuttal testimony addresses the following issues

1. Recommendations with respect to the proper classification and allocation of PacifiCorp production costs are made in the direct testimony of Mr. Maurice Brubaker, on behalf of the Utah Industrial Energy Consumers (UIEC), and the direct testimony of Mr. Paul Chernick, on behalf of The Utah Office of Consumer Services (OCS). Mr. Brubaker recommends classifying production costs as 100% demand-related. Further, he recommends two alternatives for allocating demand-related production costs. His first alternative, and apparently his preferred, is to allocate all demand-related production costs based on the Peak Responsibility method. This method would allocate demand-related costs to customer classes based on the RMP system three highest month coincident peaks (3CP) which reflect class contribution to the system peak during the summer months of June through August. His second alternative proposes the Average and Excess Demand method (AED), which is a hybrid allocation methodology that combines class average demand (or energy) with class peak demand. Conversely, Mr. Chernick recommends classifying production costs at least 50% demand-related and 50% energy-related. Mr.

Chernick supports the Equivalent Peaker methodology as a basis for classifying production costs. The Equivalent Peaker method classifies the demand-related component of a production asset based on fixed costs of a combustion turbine (CT), assuming that a CT is a proxy for system capacity cost. The remaining costs over and above that of a CT are then classified as energy-related. Mr. Chernick supports this method by referring to the pricing of capacity and energy in current electricity markets. My rebuttal testimony will identify shortcomings of both approaches and suggest an action plan to resolve this issue in the case.

2. In the direct testimony of Mr. Chernick, page 17, lines 358 through 365 he suggests that the allocation of cost in the PacifiCorp Jurisdictional Allocation Model (JAM) does not need to be consistent with the allocation of cost in the RMP COS model. My rebuttal testimony will explain why it is important to classify costs consistently between the two models, allowing for some flexibility with respect to applied allocation factors.

3. There are various proposals related to rate spread in the testimonies of Mr. Kevin Higgins on behalf of Utah Association of Energy Users (UAE); Mr. Paul Chernick and Mr. Daniel Gimble on behalf of OCS; and Mr. Thomas Brill on behalf of the Division of Public Utilities (DPU). My rebuttal testimony will comment on the appropriateness of the various rate spread proposals.

II. CLASSIFICATION AND ALLOCATION OF PRODUCTION COSTS

Q. Mr. Mancinelli, have you reviewed the direct testimony of Mr. Brubaker and Mr. Chernick regarding their proposed classification and allocation of production costs?

A. Yes I have. Mr. Brubaker recommends that 100% of production fixed costs be classified as demand-related. Further he recommends that costs classified as demand-related should be allocated to the various rate classes using a 3CP method or alternatively an AED method. Mr. Chernick proposes that production function costs should be classified primarily as energy-related using the Equivalent Peaker Method or at least production function costs should be classified as 50% energy-related and 50% demand-related. Mr. Chernick supports his recommendation by pointing to the pricing structure in various wholesale power markets.

Q. Do you agree with Mr. Brubaker's or Mr. Chernick's recommendations related to the classification of fixed production costs?

A. No, I do not believe that either approach is appropriate.

Q. Please explain further.

A. First, I will address Mr. Brubaker's proposal to classify all generation assets as 100% demand-related. It is true that much of production non-fuel operation and maintenance costs, depreciation expense, and the associated return on ratebase are fixed from a cost accounting perspective. However, classifying costs strictly from a cost accounting perspective does not recognize the used and usefulness of the underlying asset from a planning and operational perspective. Utilities add a variety of generation resources to their power supply portfolio to meet the overall capacity and energy needs of the system. Assets are selected giving consideration to a variety of factors including the system's need for low cost energy, load following on an hourly and seasonal basis and meeting system peak demand. Other considerations include compliance with environmental requirements, fuel diversity, quick start capability and other unique operating requirements.

From a cost of service perspective, customers should pay their fair share of generation assets which they find used and useful during the course of the year. A good measure of the usefulness of a specific generating resource is the reasoning and justification supporting the assets inclusion into the overall generation portfolio from a planning perspective. From this perspective, classifying all generation fixed costs as 100% demand-related undervalues the energy benefit that certain assets provide to the various customer classes during the year. For example, let's look at a typical baseload unit which is large and capital intensive compared to an intermediate or peaking unit. Baseload units have relatively high fixed costs and low variable costs. They are designed to run all the time and have high capacity factors. A capacity factor is a measure of actual plant output over a period of time compared to its potential output. A power plant running around-the-clock at full output for a period of one year would have an annual capacity factor of 100%. Typically baseload units have annual capacity factors greater than 70%. Baseload units are designed to be on-line and produce power all the time. Therefore, the design and operation of a baseload unit provides capacity over most hours during the year. From a cost of service perspective, this demand accumulated over time looks a lot like energy and can be classified as such. In this example, classifying baseload costs between demand and energy can be done simply by looking at the unit's annual capacity factor. A baseload unit with a 70% annual capacity factor maybe classified as 70% energy-related and 30% demand-related. Alternatively, the

Equivalent Peaker Methodology may be acceptable as this method recognizes the energy benefit associated with the high fixed cost investment of a baseload resource.

A key point in this determination is that different generation resources have different purposes and uses on the system. The classification of the underlying costs should be flexible enough to consider these differences. Mr. Brubaker suggests that all generation fixed costs, regardless of planning and operational characteristics, be classified as 100% demand. This one-size fits all approach is not desirable and results in inequitable cost allocation, particularly when combined with the 3CP demand allocation method that he has proposed.

Q. Mr. Mancinelli, your testimony suggests that the Equivalent Peaker Method may be an acceptable method for classifying base load generation costs, how does that differ from Mr. Chernick's proposal?

A. Mr. Chernick proposes that all generation costs should be classified primarily as energy-related using the Equivalent Peaker Method or at least 50% energy-related and 50% demand-related. Although I suggest in my above testimony that the Equivalent Peaker Method may be an acceptable approach for classifying certain baseload unit costs, it is not a uniformly acceptable approach for all generating assets. Mr. Chernick supports his recommendation by pointing to various wholesale power market pricing signals as an indicator of underlying value and cost classification. Mr. Chernick is confusing market pricing structure on an energy basis with the underlying cost structure of a utility. Markets set prices based on hourly marginal costs. Markets that do not have separate capacity pricing set hourly prices based on supply bids, which include the variable costs associated with the marginal unit plus a scarcity or capacity charge. Markets with separate capacity pricing mechanisms price hourly market energy based on variable costs associated with the marginal unit plus a predetermined capacity price. This predetermined capacity price often uses the cost of a CT as a proxy for the marginal cost of capacity. Generating units that are not on the margin, such as baseload units, recover both fixed and variable costs through these pricing structures as the hourly market clearing prices are often above the full embedded cost of production. Using the power market pricing structure to justify classifying the majority of production costs as energy-related is moving away from an embedded cost approach of cost allocation to a marginal cost approach. Because the approach by Mr. Chernick is selective and focused solely on the production function the result does not reflect cost of service from either an embedded cost or marginal cost perspective. In conclusion, using power market pricing as a basis for classifying production plant in an embedded cost of service study is not supportable.

Q. Mr. Mancinelli, please comment on Mr. Brubaker's recommendations with respect to allocating demand-related production costs based on the 3CP method.

A. The 3 CP method allocates production demand-related costs to the various rate classes based on the class contribution to the system coincident peak during the three peak demand months of June-August. Such an approach ignores the class contribution to the system peak during the other nine months of the year. The 3CP approach penalizes customers for contributing to the system peak. The 3CP approach may be warranted from a policy perspective as the allocation approach assigns all corresponding demand-related costs to the summer season. This would likely result in a greater summer/non-summer cost of service differential for RMP customers. Such a cost of service differential could aid in the development of rate structures that could send stronger pricing signals during the summer season with the objective of retarding growth of the summer peak demands. However, rate design is the most important aspect of this strategy. Although a 3CP allocation method would allocate more demand-related costs to the summer season, the demand response one would expect from customers due to higher rates could be undermined with rate structures that do not give the appropriate punitive time-of-use pricing signals during times of the system peak.

Beyond a policy justification, the 3CP method does a poor job of matching the demand benefit provided by all generation resources over the course of the year and may give certain customer classes a free-ride with respect to paying for demand-related costs incurred by RMP. As I mentioned earlier in my rebuttal testimony regarding classification of costs, different generation resources provide different planning and operation benefits to the system and its customers. Treating all generation assets uniformly makes little sense. To illustrate let's consider the Outdoor Lighting class of service. Outdoor lights are generally a highly predictable load, triggered by photovoltaic cells that operate from dusk to dawn. During the summer season, on the RMP system, system peaks occur between the hours of 4:00 pm to 5:00 pm. Since these are daylight hours, outdoor lighting would not contribute to the system peak and would be allocated zero demand-related costs under the 3CP allocation method. This result ignores the benefit that this class of services receives from the production function the remainder of the year, particularly in the months of November and December when outdoor lights contribute to the system peak. Classifying a portion of fixed production costs as energy-related solves a portion of this problem and allocating the demand-related costs correctly solves the rest. Using the CP allocation approach applied to fixed costs, CPs should match the operational use of the various generation assets. Demand-related components of baseload units should be allocated on a 12 CP basis reflecting the year-round usefulness of these assets. Peaking units should be allocated to the appropriate peak months as discussed by Mr. Abdulle in his rebuttal testimony. Intermediate units that follow load should be allocated by looking at CPs during shoulder months or a 12CP allocation may be appropriate.

In conclusion, I do not agree with Mr. Brubaker's recommendation to allocate demand-related costs related to all production assets using a 3CP approach. This allocation method combined with classifying 100% of fixed costs as demand-related is an especially onerous combination resulting in zero demand-related cost responsibility being borne classes in nine of the months in the year. This approach creates an inequitable result. CP allocation methods should match the operational use of the asset.

Q. Mr. Mancinelli, please comment on Mr. Brubaker's recommendations with respect to allocating demand-related production cost based on the AED Method.

A. The AED method is a hybrid method for allocating demand costs recognizing that generation assets benefit customers during all hours of the year as well as peak hours. The AED method effectively allocates demand-related costs to each customer class based on a mix of energy (average demand) and capacity based on class Non Coincident Peak (NCP). The ratio of average demand to system maximum coincident demand reflects the system average annual load factor. Load factor is a ratio of average load over a period of time, in this case one year, compared to peak load. Therefore, the effect of using this approach is to allocate production costs based on system energy requirements compared to peak demand requirements. For the RMP system during the test year, the annual system load factor is approximately 72% as shown in the following formula:

$$\left(\frac{kWh\ Sales_{(input)}}{kW_{(input)} \times 8760}\right) = \frac{23{,}161{,}564{,}000}{3{,}672{,}684 \times 8760} = 72\%$$

Therefore under the AED method 72% of the demand-related costs would be allocated to the classes based on energy. The remaining 28% would be allocated to the classes based on the ratio of the class NCP less average demand compared to the sum of class NCP's less average system demand. The advantage of this approach is that it is relatively simple to apply and it does reflect that a significant portion of generation resources provide value to all customer classes during all hours of the year. The approach also penalizes classes with poor load factors whether or not they contribute to the system peak. Therefore, this method does not factor the seasonal diversity between classes into the result. Also, the AED method is applied to all generation resources uniformly and does not reflect demand-related cost differentials between peaking, intermediate and baseload units. Given its simplicity, the AED method may be an acceptable, albeit less refined, approach rather than classifying and allocating individual generating assets based on their planning and operating characteristics.

Q. Mr. Mancinelli can you please summarize the various proposals with respect to classifying and allocating production costs based on the direct testimony provided in this case?

A. Yes. The table below summarizes the approach used by RMP and those proposed by the various interveners.

Proposed Classification and Allocation Methods

	RMP	UIEC/3CP	UIEC/AED	OCS
Classification of Fixed Production Costs				
Demand	75%	100%	28%	50%[1]
Energy	25%	0%	72%[2]	50%[1]

1. The Peaker Equivalent method applied to all production fixed costs would result in a significantly higher energy classification than 50%.
2. From a cost allocation perspective, average demand equals energy.

On the surface, the AED method is similar to the equivalent peaker method proposed by Mr. Chernick; however, the difference between the methods can be found in the allocation of the demand-related costs. Under the AED method, excess demand is allocated to each class based on the classes annual NCP. Whereas, under the equivalent peaker method, demand-related costs are allocated based on a 12 CP.

Q. Given your testimony regarding the classification and allocation of production costs, what is your recommendation with respect to the classification and allocation of transmission costs?

A. Currently RMP classifies and allocates the transmission function in a similar manner as the production function. Mr. Brubaker proposed that transmission be classified and allocated in a similar manner as well. I endorse this approach assuming that the production and transmission systems are truly integrated. The transmission investment delivers power from generators over all hours during the year. Also, the investment is sized giving consideration to generation capacity, location of generating facilities and the size and location of system loads. Therefore, classifying transmission investments as both demand-related and energy-related represent a fair assessment of the usefulness of these assets over the Test Year. Allocation of demand-related costs should be allocated based on composite of the various demand-related allocation methods used on the allocation of generation assets.

Q. Mr. Mancinelli, given the direct testimony of Mr. Brubaker and Mr. Chernick and RMP's current approach with respect to the classification and allocation of generation costs, what do you recommend?

A. I strongly recommend that classification and allocation methods applied to PacifiCorp generation assets match the used and usefulness value of the underlying assets from a planning and operational perspective. Therefore, any single classification approach applied uniformly to all generation assets is overly simplistic and renders a less than desirable result. A suggestion would be to consider each unit's approximate capacity factor in the determination of demand-related and energy-related costs. As mentioned earlier in my testimony, capacity factor is a measure of unit energy output; as such it is a good indicator of the mix of demand and energy-related costs associated with a given unit. I recommend that a working group be established by the Commission with the specific charge of discussing, identifying and recommending the appropriate cost classification for various kinds of generation resources within the PacifiCorp system.

Q. Mr. Mancinelli do you have any further comments with respect to the classification and allocation of costs in this proceeding?

A. Yes. With respect to Mr. Chernick's testimony page 17, lines 358 through 365, he testifies that the Commission has found it appropriate to use different class allocators between the jurisdictional allocation model and the RMP COS model. I agree that allocation factors may differ as long as the underlying cost classification is preserved. For example, if a cost item is classified as demand-related in the jurisdictional allocation model it must be classified as demand-related in the COS model also. This preserves the underlying rationale for cost causation. With this in mind, allocation methods may vary depending on the unique circumstances in the RMP COS model compared to that in the jurisdictional allocation model. For example, certain demand-related costs may be allocated to each jurisdiction using a 12CP method in the JAM. In the RMP COS model, these same demand-related costs may be allocated to the customer classes based on a 3CP or similar approach reflecting the pronounced summer peak in the RMP system.

Q. Mr. Mancinelli do you have any comments with respect to the proposed rate spreads presented by the various parties?

A. Given the reduction in revenue requirement indicated by Mr. Thomas Brill, representing DPU, the significant issues with RMP's current approach to cost allocation and the integrity of load data as described by various witnesses, I support Mr. Brill's rate spread recommendations as found in his supplemental direct testimony of October 29, 2009. Once significant issues associated with RMP's cost of service analyses are satisfactorily addressed, I recommend further movement toward rate spreads that are in more precise alignment with the cost of service.

Q. Does this complete your rebuttal testimony?

A. Yes it does.