STATE OF UTAH

BEFORE THE PUBLIC SERVICE COMMISSION

The Application of Rocky Mountain	**)**	
Power for Authority To Increase Retail	**)**	**Docket No. 09-035-23**
Electric Rates	**)**	

REBUTTAL TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE UTAH OFFICE OF CONSUMER SERVICES

Resource Insight, Inc.

NOVEMBER 12, 2009

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I. Identification

Q: Please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Are you the same Paul Chernick who filed Direct Testimony in this case?

A: Yes.

Q: What is the purpose of your rebuttal testimony?

A: I will respond to certain cost-allocation issues raised in the testimony of Messrs Joseph Mancinelli on behalf of the Division, Maurice Brubaker on behalf of the Utah Industrial Energy Consumers (UIEC), and Kevin C. Higgins on behalf of the Utah Association of Energy Users.

Q: What issues do you address?

A: I address the following five issues raised by these witnesses:

- Changes to Utah Retail Class allocators to be consistent with the jurisdictional study (JAM), as proposed by Mr. Mancinelli;
- Classification of wind resources as 100% energy-related in the COS study, as recommended by Mr. Mancinelli;
- Adjustment of residential and commercial summer load to reflect weather sensitivity, as proposed by Mr. Brubaker;
- Calibration of the loads of sampled classes to close the gap between the Utah peak of the JAM and that of the COS study, as proposed by Messrs Higgins and Brubaker;

- Classification of generation and transmission plant as 100% demand-related, and allocation of that plant based solely on class-peak contribution in three summer months (June–August), as proposed by Mr. Brubaker.

II. Consistency Between Jurisdictional and Class Allocation Studies

Q: What support does Mr. Mancinelli offer for his proposal that the JAM and COS Study factors be consistent?

A: First, he suggests that Commission's approval of the Multi-State Process Stipulation in Docket 02-035-04, which determined the JAM allocation factors, set a precedent that is also binding on the allocation factors used in the COS-study model. Second, he asserts that the JAM allocators "dictate important information related to the underlying cost drivers" (DPU Exh. 5.0 at 5).

Q: Has Mr. Mancinelli provided adequate justification for requiring consistency between the JAM and COS study allocators?

A: No, for several reasons. First, the JAM allocation factors reflect an agreement among the majority of PacifiCorp states on the use of the Revised Protocol Method, a method that does not necessarily follow cost causality. Interstate negotiations must not restrict or supersede the Commission's decisions involving class cost-of-service matters. Second, in Docket No. 97-035-01 (Order at 113), the Commission allowed for dissimilar treatment of costs between the inter-jurisdictional and class studies for "good and sufficient cause." Improvement in class allocations the better to reflect cost causation surely qualifies as a good and sufficient cause.

In fact, Mr. Mancinelli concedes that rigid adherence to JAM allocations in the COS model is inappropriate when he proposes that wind resources be classified as 100% energy-related in the COS model but not in the JAM:

> Given the unpredictable dispatch of wind resources, I recommend allocating these costs based on energy only. However, using energy to allocate wind resources in the JAM would alter the jurisdictional revenue requirement. Recognizing that such an adjustment impacts the revenue requirements for all jurisdictions within PacifiCorp, I recommend, that for this case, that wind assets be separated in JAM yet remain allocated based on the SG–System Generation Allocation factor. This approach will identify costs associated with wind resources but will not change the RMP revenue requirement as determined in the JAM. However, in the RMP COS model these costs should be assigned to the production function and allocated to the rate classes based allocator F30.

III. Allocation of Wind Resources

Q: What is the basis for Mr. Mancinelli's proposal to classify wind resources as 100% energy-related?

A: In his view, wind resources provide energy, but not reliable capacity. He asserts that this departure from strict application of JAM allocations in the COS study is warranted because wind is "fundamentally a different type of resource compared to traditional fossil-fuel generation" (DPU Exh. 5.0 at 5).

Q: Do you have any response to Mr. Mancinelli's proposal to classify wind resources as 100% energy-related?

A: I do agree that wind resources should be allocated primarily on energy, but not entirely. Wind resources do have some capacity value that should be recognized for classification purposes.

I do not agree with Mr. Mancinelli's contention that wind merits a different approach from other resources simply because it is a new technology and non-fossil-fueled. This distinction is irrelevant to cost-based classification. Rather, *all* generation plant should be classified based on the causes of the investment and on the resulting benefits.

IV. Effect of Weather on Loads

Q: What is Mr. Brubaker's criticism of RMP's weather normalization?

A: The utility adjusts the historical class load data to a monthly energy forecast that "is based on the 20-year average monthly temperatures" (UIEC DR 2.14). As I understand Mr. Brubaker's testimony, he asserts that RMP's weather-normalization of the energy forecast understates the peaks of rate classes with weather-sensitive loads. He contends that, instead, the load data from 2008 (already a very hot summer) should be adjusted to an energy forecast that assumes some extraordinary weather conditions.

Q: Is Mr. Brubaker correct?

A: No, for at least three reasons. First, RMP's COS study reflects a projection of normalized revenues, costs and loads based on historical load profiles. Mr. Brubaker has not explained what data he would rely on in his extreme-weather COS study, let alone justify its implementation.

Second, the variability of class load within each month, which is the primary determinant of the relative class loads at peak, is derived from RMP's historical load profile for each rate class and is therefore designed to contain realistic peaks.

Third, Utah experienced a very hot summer in 2008, and the 2008 class load profiles actually reflect higher-than-normal temperatures.

V. Reconciling Jurisdictional and Class Load Estimates

Q: Please summarize the proposals by Mr. Brubaker and Mr. Higgins to adjust or "calibrate" Utah class peak loads so that they equal total Utah jurisdictional peak loads?

A: Beginning on Page 13 of his direct testimony, Mr. Brubaker asserts that the sum of Utah class-peak loads should approximate the total Utah peak load used in the JAM and that any difference or gap between the Utah class and jurisdictional loads must be due to the Company's failure to accurately estimate the peak loads for the classes (primarily Schedules 1, 6, 23, 10) without interval meters, whose loads shapes are based on sampled data. He further alleges that (1) the under-stated loads for the sample classes results in an over-allocation of costs to Schedules 8 and 9 (at 14, ll. 21–24) and (2) if the class loads are calibrated to the total jurisdictional peak load through upward adjustments to the peak loads of the sampled classes, then COS results are much closer for the major classes (at 19, ll. 6–11).

Mr. Higgins makes a similar argument, but in much less detail.

Q: Do you agree with Mr. Brubaker's underlying premise that the Utah class peak loads should equal the total Utah jurisdictional peak load and subsequent recommendation that sampled rate classes' peak demands should be calibrated upwards to close the gap between the class and jurisdictional totals?

A: No, for two reasons.

First, as Company Witness Thornton indicates at 10–11 of his direct testimony, the Utah jurisdictional and Utah class-peak load forecasts are based on different methodologies. There is no reason to expect the two methods to produce similar results, and there is no need for them to do so. Allocations are based on the *relative* peaks of jurisdictions in the JAM and of retail classes in the COS model.

Second, other factors may contribute to the “gap” between the Utah jurisdictional and class loads that are unrelated to errors in load research data. For example, the following factors may cause the figure to diverge:

- Partial requirements customers would likely be included in the jurisdictional peak-load total but not included in the sum of class peak-load totals.
- Loss factors are estimated and may understate peak losses on very hot, high-load days.
- Measurement of border loads is uncertain, as discussed by Mr. Thornton in his direct testimony at 11) and by The Load Research Working Group Report to the UPSC (July 1, 2002, at 12).

These and other factors are unrelated to errors in load-research data.

Arbitrarily increasing the estimated loads of the sampled classes would likely overstate their cost responsibility. Therefore, I recommend that the Commission continue to recognize the distinctions between methods for forecasting jurisdictional and class peak loads as set forth in Mr. Thornton’s direct testimony and not adopt Mr. Brubaker’s calibration proposal.

VI. Allocation of Generation and Transmission Plant

Q: What is Mr. Brubaker’s proposal for classifying costs of generation and transmission plant?

A. Mr. Brubaker proposes that 100% of PacifiCorp’s generation and transmission plant be classified as demand-related.

Q. Does Mr. Brubaker take the position that fuel costs have no effect on resource decisions?

A: No. Mr. Brubaker recognizes that "different technologies have different combinations of fixed costs and variable costs" and that the economic resource choice depends upon the amount of energy the system requires from the plant.

Q: Then why does Mr. Brubaker propose classifying all generation plant as 100% demand-related?

A: He contends that once generation plant is installed, its costs are constant over the year, and therefore "fixed" in the short run. In Mr. Brubaker's view, all "fixed" costs are 100% demand-related; only costs that vary in the short run in response to load levels should be considered energy-related.

Q: Does this argument have any merit?

A: No. Nothing about "fixed" costs makes them inherently demand-related. Mr. Brubaker does not show that costs that are invariable over the period of a year are caused by or serve only peak demand, rather than energy. Mr. Brubaker attempts to use semantic legerdemain to replace "demand-related" with "fixed in the short term," rather than offer any useful evidence on cost causation.

Indeed, the concept of "fixed" generation costs is anachronistic. Long ago, a utility that had a coal plant that was not needed for its own load at a particular hour would have no choice but to turn down the coal plant. Today, with the extensive interconnection of utility systems, unused capacity can be traded into off-system markets. Consequently, it is no longer realistic to consider generation plant as a fixed burden on ratepayers.

Embedded cost studies consider the cost basis for the investment, including the economic tradeoffs that led to the resource decision. The purpose of COS studies is to determine a fair sharing of the costs and benefits of existing plant investment. Classes with high load factors throughout the year benefit more from the low-cost energy from baseload plants than do low-load-factor classes, so they should pay more of the fixed costs of the baseload plants.

The Commission has firmly rejected Mr. Brubaker's position that all generation and transmission costs are driven by peak loads and I recommend that it continue to do so.

Q: Does Mr. Brubaker suggest an alternative approach?

A: Mr. Brubaker recognizes that utilities select resources to minimize the costs of meeting their load shapes, and describes a hypothetical analysis of the generation system that could be constructed for each customer class in isolation. However, he considers this analysis to be impractical and does not recommend it.

Q: Is there any merit in Mr. Brubaker's argument that only his hypothetical approach would be appropriate?

A: No. Mr. Brubaker proposes one conceptual approach for dividing up the costs of generation between energy and demand, which would require a complicated analysis of the optimal supply mix for hypothetical mini-utilities (including reserves) and the development of rules for allocating each actual plant, purchase, sale, and associated fuel and energy charges among those hypothetical utilities. I have proposed a much simpler approach, based on the peaker method. Other approaches may also be reasonable. The role of the Commission is to choose among feasible causation-based approaches, of which mine is the only one in the record. Mr. Brubaker's suggestion that some impossible method would be ideal, and the Commission should therefore throw up its hands and use his arbitrary 100% demand allocation, is untenable.

Even if his impractical alternative approach were appropriate, which I do not believe, Mr. Brubaker does not demonstrate that it would produce anything close to a 100% demand allocation, or that a 100% demand allocation is even close to a simple second-best option. My analysis suggests that, if anything, 100% energy allocation is more appropriate for coal plants than 100% demand.

Q: What is the basis of Mr. Brubaker's proposal that all generation plant be allocated among classes on a 3-CP allocator?

A: In his view, the summer peak in Utah is increasingly dominant and drives the need to build or acquire capacity (Brubaker Direct at 20–21).

Q: Has Mr. Brubaker demonstrated that loads in the other nine months have no effect on PacifiCorp's resource planning decisions?

A: No. PacifiCorp's power-supply system is affected by all twelve monthly peaks, for the following reasons:

- The PacifiCorp system has a strong winter peak. The Company invests in generation resources to meet the year-round needs of the PacifiCorp system, not just the Utah jurisdiction alone.
- PacifiCorp normally schedules generating-unit outages during fall or spring months. Thus, it must have generation resources to meet demand when some units are unavailable because of scheduled outages in the shoulder periods.
- Loads outside the summer months contribute to the loss-of-load probability and therefore affect the need for capacity.
- Loads in non-summer months reduce PacifiCorp's ability to sell capacity in the wholesale market, increasing net power cost.

Q: Has Mr. Brubaker provided any evidence that the Commission should supplant the existing 12-CP Method with a 3-CP Method?

A: No. Mr. Brubaker has provided no evidence that PacifiCorp plans and operates its system in a manner that would support moving to a 3-CP generation allocator.

Q: Does this conclude your testimony?

A: Yes.