STATE OF UTAH

BEFORE THE PUBLIC SERVICE COMMISSION

The Application of Rocky Mountain	**)**	
Power for Authority To Increase its	**)**	**Docket No. 11-035-200**
Retail Electric Utility Service Rates in	**)**	**Witness OCS-7D COS RD**
Utah and for Approval of its Proposed	**)**	
Electric Service Schedules and Electric	**)**	
Service Regulations	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE UTAH OFFICE OF CONSUMER SERVICES

Resource Insight, Inc.

JUNE 22, 2012

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I. Identification and Qualifications

Q: Mr. Chernick, 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: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further described in my Exhibit COS 7.1 (Chernick).

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than two hundred and fifty times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty states and five Canadian provinces, and two U.S. Federal agencies.

Q: Have you testified previously before the Commission?

A: Yes. I testified on behalf of the Utah Office of Consumer Services ("the Office") in the following dockets:

- Docket No. 98-2035-04, on the proposed acquisition of PacifiCorp by Scottish Power. My testimony addressed proposed performance standards and valuation of performance.
- Docket No. 99-2035-03, on the sale of the Centralia coal plant. My testimony addressed the costs of replacement power, the allocation of plant sale proceeds, and the potential rate impacts on Utah customers of PacifiCorp's decision to sell the plant. I testified that the sale of Centralia was not in the interest of ratepayers and that if the Commission approved the sale it should allocate more of the sale proceeds to Utah to mitigate potentially high replacement power costs. The Commission adopted this latter recommendation as part of approving the sale.
- Docket Nos. 07-035-93, 09-035-23, and 10-035-124 on the reasonableness of RMP's Cost-of-Service study. I also assisted the Office in the development of its rate-design proposal.

- Docket No. 09-35-15, on the need for RMP's proposed Energy Cost Adjustment Mechanism.

I also assisted the Office in analyzing various issues in the multi-state process. These issues included resource planning, cost allocation of generation-and-transmission plant, regulatory policy and risk analysis.

II. Introduction

Q: On whose behalf are you testifying in this rate case proceeding?

A: My testimony is sponsored by the Office of Consumer Services.

Q: What issues does your testimony address?

A: I evaluate the Cost-of-Service Study ("COS Study" or "COSS") and the Marginal-Cost Study filed by Rocky Mountain Power ("RMP" or "the Company") and recommend certain improvements be made to the Company's analyses in the next rate case filing. I pay particular attention to the calibration of the COS-Study load data, which was first introduced by RMP in Docket 10-035-124, and to certain classification and allocation methods. In addition, I address RMP's reliance on these COS and Marginal-Cost studies for its revenue-spread and residential-rate-design proposals.

III. Evaluation of the Company's Cost-of-Service Study

Q: What is the purpose of the cost-allocation process?

A: The purpose of the cost-allocation process is the fair assignment of the total Utah jurisdictional revenue requirement to the various tariffed rate classes.[1] A

[1] There are also cost-allocation implications for certain special contract customers due to pricing provisions in their respective contracts.

fundamental principle of the process is that allocation based on cost causation results in an equitable sharing of embedded costs.

Q: What role should the embedded COS Study play in revenue allocation?

A: Any embedded-cost-based COS study is approximate and based on judgment. Its reliability is also affected by limits on the accuracy of the load data. For these reasons, it should serve only as a guide to class rate spread.

Q: Should the Commission expect classification and allocation methods to change over time?

A: Yes. A COS-study methodology should not be fixed in stone. It should be revised as needed to address changes in any of the following:

- the conceptual models of cost causation;
- data availability;
- the environment in which utilities operate, such as the structure of wholesale markets and cost patterns;
- energy and regulatory policy.

Q: What COS-study issues does your testimony address?

A: My testimony on the COS Study addresses two basic areas:

- the reliability of the Company's load data,
- specific classification and allocation factors.

A. Evaluation of the Load Data

Q: What load data issues does your testimony address?

A: My testimony addresses the following issues:

- the validity of the RMP's use of calibration to reduce a so-called gap between the sum of retail class peaks and the Utah jurisdictional peak,
- the unreliability of irrigator load data,

- the failure by RMP to weather normalize retail class peak loads.

1. Calibration

Q: What is the Company's justification for the calibration of load data?

A: According to Mr. Thornton's Direct (at 18), "The calibration process is based on the expectation that the sum of base year class loads should equal the total forecast jurisdictional load estimates" at PacifiCorp system monthly peaks. Calibration concerns only the forecasts of retail loads at the time of PacifiCorp monthly system peaks ("CP").

Mr. Thornton (at 19) cites the Division's conclusions from the Working Group as support for RMP's calibration process, while noting that "not all parties agreed with the process." The OCS opposed calibration.

Q: Please describe RMP's calibration process.

A: The Company follows several steps to develop load data for its COS. The calibration process (as described in Mr. Thornton's Direct at 18–21 and shown in Attachments OCS 3.29 1st Revision and OCS 3.33), is by no means a simple and transparent algorithm. The steps are as follows:

1. For the sum of retail class peaks, the process starts with the monthly dates and times of the system peaks in the base year.
2. The Company estimates the class contributions to system peaks in the base year, using adjusted hourly load research data.
3. The Company forecasts class loads in every hour in the month by applying class energy growth factors to the adjusted base-year load research data. This forecast is based on the assumption that class monthly load shapes are fixed.

4. The Company sets each monthly class contribution to system peak (CP) as the forecasted hourly load at the time of base year system peaks.

5. The Company then sums the forecasted class CPs at the base-year dates and times, and compares the results, by month, to the forecasted Utah jurisdictional CP. The jurisdictional CP forecasts are based on a different methodology and may occur at different dates and times than the class CP's.

6. Monthly class loads are adjusted to reduce the so-called gap between class and jurisdictional peaks. These adjustments are applied to the sampled classes only. The forecasted loads of the interval-metered classes are assumed to be 100% certain.

7. Where the two Utah forecasts (the sum of class and the jurisdictional peaks, both excluding the interval-metered loads) differ in any month by more than 5%, the sampled class peaks are adjusted as follows:

   - If the initial gap is between 5% and 10%, the difference in excess of 5% is spread proportionally over the sampled classes.
   - If the initial gap exceeds 10%, RMP follows somewhat of a trial- and-error process to reduce the gap by considering sum of class peaks at dates and/or times that are closer to the jurisdictional peak hour.
   - If changing the date and time fails to reduce a monthly difference to 10% or less, the excess over 5% is spread among the sampled-class loads at the original date and time. The Company used this adjustment for the May peak loads for the current COSS, because the trial-and-error process failed to reduce the May gap below 10%.

8. Finally, if necessary, monthly class CP's are adjusted in 0.5% increments to reduce the annual gap to 2%. This adjustment was not required.

Q: In what ways is the calibration of load data unsound?

A: Seeking to "correct" monthly sampling data is not a valid basis for calibration, for several reasons:

- Individual monthly differences between jurisdictional and sum of class peaks are essentially irrelevant to the COS Study.
- Calibration has little effect on the annual average difference between the sum-of-class and the jurisdictional peak loads. The "gap" is small without any calibration adjustments.
- Calibration is not a statistically valid process.
- The load research data is not the sole source of statistical error.
- Other non-statistical elements of the two jurisdictional peak forecasts contribute to the "gap."
- The calibration process in the 2012 COSS has only a small effect on the COSS results, adding an unnecessary as well as unsound element to the COSS process.

In short, a gap should be expected, given all the possible causes for differences between the two estimates of jurisdictional peak.

a) Calibration Is Essentially Irrelevant to the Cost-of-Service Study

Q: Why are the monthly differences irrelevant to the COSS?

A: The annual average coincident peaks, not the individual monthly peaks, are the basis for allocation of generation and transmission costs. And only that average is important for cost allocation. Errors in individual months may offset one another; accuracy in monthly peaks is not essential for equitable cost allocation.

Q: How close is the average sum of class peaks to the average jurisdictional peak without calibration?

A: Even before calibration, the difference between the two measures of average peak was far less than RMP's 2% target (see Table 1).

Table 1: Company Estimates of Utah vs. PacifiCorp Peak (@ Input)

		Sum of Class	
	Jurisdictional	Pre-Calib.	Calibrated
kW	43,931,266	43,557,029	43,687,655
% Gap		-0.9%	-0.6%

Source: Attachment OCS 3.29 1st Revision

Given that the annual gap is almost zero, that the individual monthly peak gaps are statistically unreliable, and that the monthly peaks are not used in the COS Study, RMP's calibration process addresses a problem that does not exist.

b) Statistical Validity of Calibration

Q: Why is RMP's calibration process an inappropriate basis for adjusting the monthly peaks of sampled classes?

A: The calibration process is inappropriate for at least the following reasons:

- When calibration alters relative class peaks, there is no way of determining whether the changes are an improvement.
- The calibration process is not a precise algorithm. For the month of May, the Company tried three different dates and ended up using the original peak hour. The choice of the trial dates (each of which produces a different F10 allocator) appears to be arbitrary.
- Calibration of individual monthly peaks holds the class load estimates to a higher reliability standard than the load research data support.

- The same adjustment is applied to all sampled classes even though the residential load research study is designed to provide data that are more accurate than the load-research samples for the other sampled classes.[2]

Q: How does RMP's calibration affect the COSS class load data?

A: The calibration increased the relative annual average peak of the Schedules 1 and 6 and reduced the relative peak of Schedules 23 and 10. See Table 2.

Table 2: Effect of Calibration on COS-Study Load Data (@ Input)

	Total Annual		Difference		Percent of Total Class Sum		
Class	Pre-Calib.	Calibrated	kW	%	Pre-Calib.	Calibrated	Increase
Res 001	15,485,218	15,615,358	130,140	0.83%	35.55%	35.74%	0.19%
Com 006	12,207,346	12,268,215	60,869	0.50%	28.03%	28.08%	0.06%
Com 023	3,082,148	3,044,949	−37,199	−1.22%	7.08%	6.97%	−0.11%
Irr 010	311,206	310,315	−891	−0.29%	0.71%	0.71%	0.00%
Sum of Sampled Classes	31,085,918	31,238,837	152,919	0.49%	71.37%	71.50%	0.15%
Total Class Sum	43,557,029	43,687,655	152,919	0.35%			

Note: Annual Load of the Irrigator Class includes load in all months.
Source: Attachments OCS 3.29 1st Rev and OCS 3.33

The algorithms RMP uses to adjust class monthly peaks have different effects on relative class peaks. The proportional spread among sampled classes maintains the relationship among those classes, but changes the allocations between large customers and sampled customers. Changes in the day and time of peaks can change the relative loads of *all* classes and therefore the allocations among them.

[2] According to Mr. Thornton, the residential class sampling was designed to achieve ±5 percent precision at the 90 percent confidence level, while the load data for the other sampled classes was expected to meet a design criteria of ±10 percent precision at the 90 percent confidence level (Thornton Direct at 6)

Q: Do others in the field recognize the problems with "calibration" as an invalid adjustment to statistical results?

A: Yes. According to the 1992 NARUC Utility Cost Allocation Manual (at179):

> …The sum of the coincident demands for all classes for any hour adjusted for losses will not equal the demand of the utility generated in that hour. This is because of sampling and non-sampling errors.
>
> When the historic test year is coincident with the year the load data was collected, the cost analyst can use the demands as estimated and calculated but usually an adjustment is made to the demands so that they sum to the actual demand of the utility in that hour. Sampling statisticians prefer that no adjustment be made because of the uncertainty as to whether the adjusted demands by class represent more accurately the class's proportion of the total demand than the statistically estimated demands. Some cost analysts have adjusted the estimated demands proportionately of only those classes that are not 100% time-recorded. This procedure, however, ignores the size of the sampling error of the various estimates and the measurement errors present in 100% time-recorded classes.

Q: How does RMP's load-research design standard differ from the calibration tolerances?

A: The Company's calibration process sets a monthly target of ±5%, so that each month's sum of class peaks is within 95% and 105% of the month's Utah jurisdictional peak. The load research studies, on the other hand, are not designed to provide any statistically valid peak estimates for single months.

In addition, RMP sets a calibration target for the annual average sum of peaks at 2%, so that the annual average sum of class peaks is within 98% and 102% of the average jurisdictional peaks.

The load-research sampling is designed to meet a much-lower level of accuracy. Annual average class peak estimates for the non-residential class are designed to be within 10% of the actual average load, and the residential within 5%, of actual average peak, with a confidence level of 90% (Thornton Direct at

6 and 21; OCS 3.23).[3] The ±2% is much more rigorous than the PURPA standard on which the sampling is based.

Q: Has the Company confirmed your characterization of the accuracy standard of its load studies?

A: Yes. In response to OCS 10.1 in Docket No. 10-035-124, the Company explained that the design standard applies only to the annual sum of peaks, not to the individual monthly peaks:

> Mr. Thornton's testimony does not assert individual peaks will reflect an "accuracy of plus or minus 10 percent at the 90 percent confidence level." Rather, it states that this is the design standard for the "variable of interest" (lines 73-74). The variable of interest for the load studies referenced is the average demand at the time of the monthly system peaks, as measured over a twelve consecutive month period.

c) Other Sources of Statistical Error

Q: What other sources of statistical error can produce a discrepancy between the two estimates of jurisdictional peak?

A: The following errors can produce such a discrepancy:

- Calibration is applied to forecasts of retail class loads, not to base-year sampling data. These forecasts come with additional modeling and statistical regression errors that can also cause discrepancies between the class and jurisdictional peak loads. This error is independent of the uncertainties in load research data.
- There is data and forecasting error in the jurisdictional CP estimates, not just in the sum-of-class peak estimates.

[3] RMP designed its residential sampling to meet a higher standard: a confidence level of 90% that any particular load estimate is within 5% of the actual load (Thornton Direct at 6). However, RMP ignores this higher accuracy in its calibration process.

- The calibration process incorrectly treats historic census data and the forecasted peaks of census customer classes as having zero error.

Q: Please explain the source of forecasting error.

A: Every regression analysis used in the forecast of retail class sales and peak has a confidence interval around its estimates of the best-fit equation, and an even wider prediction interval around the projection for any particular set of inputs.

Q: Is the JAM estimate of Utah's contribution to system peak also based on regression analysis?

A: Yes. For each state, the Company uses regression analysis to develop forecasts of all hourly loads (not just on the hour of the system peak), as well as forecasts of monthly peaks and monthly energy.

The derivation of the Utah CP from these regressions is an additional source of error. In this calculation, RMP turns the hourly forecasts into a monthly load duration curve; shifts the curve vertically to fit the state peak and rotates the curve to fit the energy forecast; turns the load duration curve back into hourly loads; adds loads across states and selects the system peak hour.

There are clearly many assumptions and potential errors in this process and they are sources of error in the historical and forecasted jurisdictional peaks.

Q: Does the Company agree that there is error in the jurisdictional peak forecast?

A: Yes. In the Load Research Working Group, RMP took the position that

> …jurisdictional measurements are also not error free. (For example, meters are not always functioning properly, the data sets may not be as complete as assumed, and allocations of interstate transmission transactions may not be completely accurate.) Division's Working Group I-II Final Report at 14.

Q: Do you agree that the calibration band is large enough to encompass uncertainty in both sum-of-class and jurisdictional peaks?

A: No. First, as explained above, since there is no statistical measure of the uncertainty in the individual monthly sum-of-class peak estimates, there is no support for claim that a 5% band is reasonable. Second, the uncertainty in the forecast of average annual sum of sampled class peaks, by itself, is greater than ±5%. Uncertainty in the jurisdictional forecast requires a band that is greater than 5%. Third, The Company mischaracterizes the calibration; the process has an ultimate target of no more than ±2%, not ±5%.

Q: How does the calibration process treat the base year and forecasts of the peaks of census classes as if they were certain?

A: The calibration process makes adjustments only to the forecast peak loads of sampled classes, not to the forecast peak loads of census classes.

Q: Does the Company's explain why it has not allocated any part of the gap to the census classes?

A: No. In fact, RMP's statements refute this treatment of the census load data. RMP agrees that there is error in the load data for the metered classes (Division's Working Group I-II Final Report at 14). In addition, according to its response to DR OCS 3.25,

> The Company has not assumed that forecasted hourly load of Direct Measurement customers are certain.

d) Other Sources of the Gap

Q: What forecast elements other than statistical error can lead to the gap?

A: In addition to statistical error, there can be several reasons why the two measures of Utah average peak do not agree, as follows:

- The class CP forecasts and the jurisdictional forecasts are based on different methodologies.
- The JAM methodology assigns to the Utah jurisdiction the losses from wholesale transactions and power transfers through Utah, inflating Utah loads estimated for the jurisdictional model. This was the one of the primary reasons calibration was abandoned by the Company in 2002.

Q: How do the methodologies used to forecast jurisdictional peaks and class peaks differ?

A: The jurisdictional forecasts are the result of regressions on historical jurisdictional hourly load data, for each hour. The forecast of jurisdictional load shape is normalized through regressions that contain dependent variables for weather.

The COS loads are the result of completely separate regressions. Furthermore, the load shapes and the dates and times of peaks are based on what happened in one actual year only, the base year. There is no attempt to develop a class load shape for a normal year. Only the forecasted class energy growth is normalized for weather through a regression on historic energy use.

There is no reason to expect that the projections resulting from two different methods—using different driving variables, one weather-normalized and the other not—will exactly match; and if they do not match, there is no reason to assume that one projection is right and the other wrong.

Q: What losses occur within Utah that are not due to Utah retail sales?

A: The sources of these losses include the following:

- sales to utilities in other states, from generation in Utah or power flowing through Utah,
- municipal and coop loads in Utah,

- power flowing from Arizona or Wyoming, through Utah, to PacifiCorp loads in Idaho and beyond.

Q: Has RMP attempted to measure these losses?

A: No. The Company has made no effort to measure these losses. RMP gives the following explanation (DR OCS 3.31):

> The Company does not track the requested information, therefore, the information is not within the Company's custody, possession or control. While the Company has Utah-specific loss figures, these are limited to retail uses of the transmission system in Utah. Accordingly, a Utah-specific estimate of losses for third-party wholesale uses of the system cannot be provided from these figures. The Company has transmission system-wide loss figures, but these are not separated into individual state results.

Q: In summary, why do you recommend against calibration of load data?

A: There is no reason to expect that the forecasted sum of class peaks would exactly equal the forecasted jurisdictional peak load, given the differences and irreducible errors in these independent forecasts. The planned improvements in the reliability of the sampled load data will not eliminate uncertainty in the base-year class or jurisdictional peak loads, the uncertainty in the class and jurisdiction load forecasts, or any of the other factors discussed above that contribute to the discrepancies between the two measures of Utah monthly peaks. Consequently, the adjustment of retail class loads to reduce that gap, even as a supposedly interim measure, violates principles of statistics and fair allocation.

2. Weather Normalization

Q: How are the JAM and COSS peak-load forecasts weather normalized?

A: While the Company has for some time used weather-normalized load shapes to determine peak loads for the JAM model, it does not weather-normalize the class load shape used in the COS Study (Thornton Direct at 17). This difference can also be an important factor accounting for some of the difference or gap between the jurisdictional and class peak loads. It also can affect the outcome of the COS Study.

Q: Can the Company eliminate this inconsistency between the JAM and COSS peak forecasts?

A: Yes. The Company should weather-normalize class load forecasts to eliminate this portion of the inconsistency between the JAM and COSS load data. Many other discrepancies will remain.

3. Irrigator Load Data

Q: Does the irrigation class present special load research challenges?

A: Yes. The irrigation loads are diverse, highly variable from year to year, and hard to characterize. Recognizing this variability, RMP used an unusually large sample size.

Q: Has the reliability of the irrigator load data used in the current COS Study been improved?

A: No. RMP has not provided any analysis to indicate that the irrigator load data has improved

Q: What has RMP's recent experience been with its irrigator load research data?

A: In the data provided in Company Witness Scott Thornton's Exhibit SDT-1 in Docket No. 09-035-23, there were sizeable discrepancies between estimated and actual monthly usage. The overestimates of irrigation class usage in the summer months (the only months for which RMP uses the irrigation load-research data) ranged from 18% in May to 62% in August. See Table 3.

Table 3: Errors in RMP's Irrigation Load Reconstruction

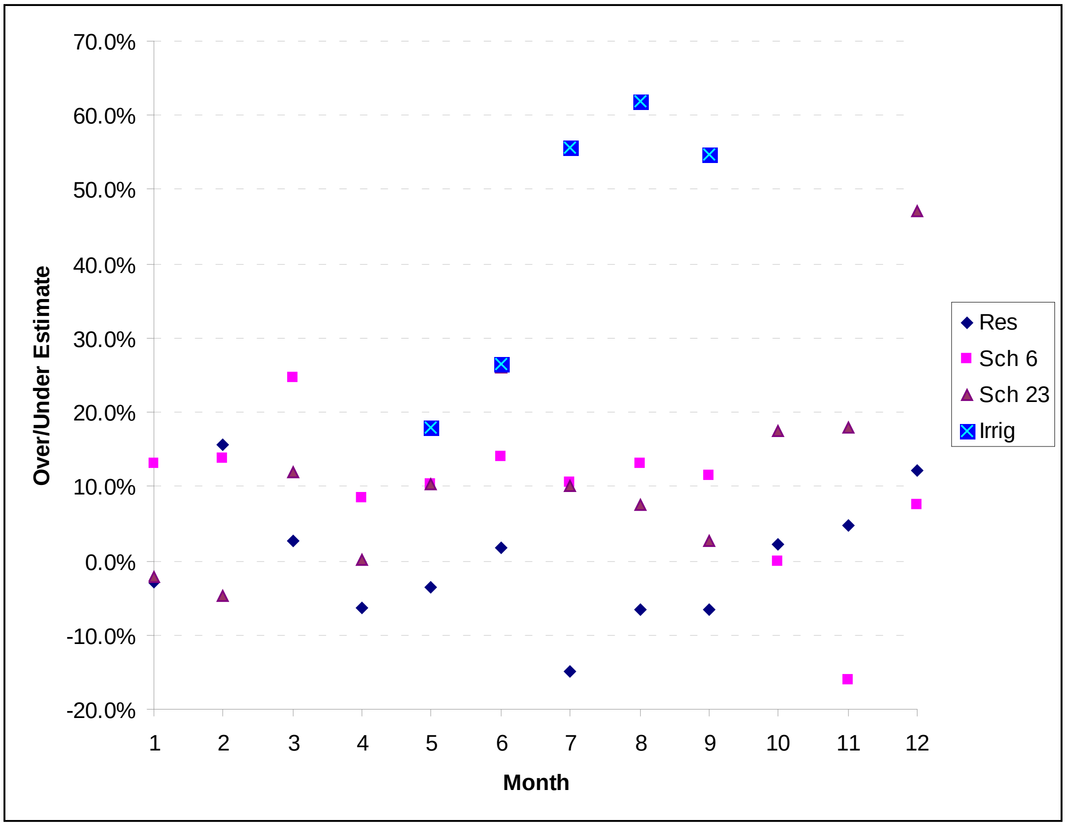
	Sample MWh	Billing MWh	Adj. Factor	Over-Estimate
May	35,079	29,728	0.8475	18.0%
June	48,924	38,702	0.7911	26.4%
July	68,699	44,108	0.6420	55.8%
August	69,803	43,086	0.6173	62.0%
September	44,524	28,760	0.6459	54.8%

The load-research data over-predicted actual usage of irrigation customers by 45% in the summer months.

Q: Were these estimation errors typical for RMP's load-research efforts?

A: No. As shown in Figure 1 below, the five months of irrigation load data included the three largest errors and five of the seven largest errors, out of the 41 monthly samples in Exhibit SDT-1.

Figure 1: Errors in RMP Load Sampling



Q: Can RMP's pro-rata adjustment to load in all hours provide an adequate correction to the estimated irrigation loads?

A: No. In its derivation of the class hourly load estimates from the sample load data, RMP's adjustment holds load shape constant. In other words, RMP assumes that the class demand factors are in constant proportion to energy use and the load profile is unaffected, no matter what the cause of the discrepancy. This is an unrealistic assumption, especially in the case of discrepancies as large as 62%. The factors that significantly alter kWh usage (such as crop rotations, changes in weather, temperature and rainfall, and customer diversity) are likely also to affect load shape.

Q: Can the current irrigator load data be relied on to support a disproportionate increase in irrigation rates?

A: No. Since the load data for this class has not come close to meeting PURPA standards and has differed sharply from actual class sales, no conclusions can be drawn about the cost of service for the irrigation class. The current irrigator load data should not be relied upon to support a major cost allocation action.

Q: What do you recommend instead?

A: I support the proposal of OCS Witness Dan Gimble, who suggests exploring the reasonableness of using historical irrigator load data to estimate a normalized load shape for the irrigation class, for normal weather and cropping patterns.

B. Classification and Allocation of Generation Costs

Q: Have you identified areas in which RMP's COS Study should be improved?

A: Yes. I have identified a number of improvements that should be made to the Company's classification and allocation factors to reflect cost causation. In particular, future RMP COS studies should recognize the following realities:

- Steam plant has become more energy-related, especially because of the recent investment in pollution control equipment.
- Wind resources are largely energy-related.
- More than 50% of firm power purchase costs are energy-related.
- Some service drops are shared by two or more customers.

I discuss each of these further below.

1. The Classification of Generation Plant

Q: How does the COS Study classify generation plant?

A: The COS Study classifies generation plant as 75% demand-related and 25% energy-related. RMP's approach recognizes that power-production facilities are built both to serve demand (i.e., to meet reliability requirements) and to produce energy economically.

Q: Is there a good analytical reason for changing the demand-energy split applied to generation plant?

A: Yes. The 75-25 split understates the portion of generation investment—particularly in coal and wind plants—that is incurred to meet energy needs, rather than peak load.

Q: Has the Commission endorsed your view that more generation plant should be classified as energy-related?

A: No, for at least two reasons. First, the Commission found that a change to the classification of generation would be inconsistent with the JAM method. Second, the Commission believed that the existing 75-25 method is supported by the stress factor analysis. (Docket No. 09-035-23 at 123).

Q: What is your understanding of the Commission's current view regarding consistency between the JAM and the COSS?

A: The Commission's position is not clear. In its Order in Docket No. 09-035-23, the Commission did indicate that changes to reflect cost causation could meet Commission approval if there were "good and sufficient cause." As the Commission stated,

> We also want to insure that these fundamental cost-of-service decisions are applied consistently at interjurisdictional and class levels…*unless good and sufficient cause shows otherwise* [emphasis added].

However, in the same Order, the Commission appeared to raise further obstacles to approval of changes to the COSS that are inconsistent with the JAM methodology:

> Any party who would like to propose an alternative to the approved methods must provide analysis to demonstrate the proposed method is also appropriate and viable at the inter-jurisdictional level. This analysis must include a level of detail to determine the impacts to Utah and other states in the PacifiCorp system of a proposed change in classification and allocation methods

It is not clear what the Commission meant by the term "viable at the inter-jurisdictional level." If that standard requires the proponent of a change to prove that the change would be accepted by all five of the other PacifiCorp states for use in a consensus JAM, it would be nearly impossible to meet. If, on the other hand, the standard is to demonstrate that the proposed change would not seriously disadvantage Utah, or would not excessively burden the majority of states, it may be possible to provide the information the Commission is seeking.

In this testimony, I present an analysis of the energy classification of generation plant, in the event that the Commission clarifies its standard so as to consider allocation factors that are not identical to those of the current JAM methodology.

Q: Does the stress-factor analysis support the 75/25 classification of generation?

A: No. The Company's stress-factor analysis determines the hours of load that drive the reliability-based need for capacity. Therefore, it is relevant to the allocation of the demand-related portion of generation plant. In particular, since it shows that hours in all months contribute to the loss-of-load-probability, it supports the 12-CP allocator. It is not relevant to the classification of plant as energy- or demand-related.

Q: Does the JAM's 75/25 split reflect costs to Utah even though it understates the energy-related portion of generation plant?

A: No.

Q: How can the energy-related portion of generation plant costs be estimated on a cost-causation basis?

A: One approach is the *peaker method,* which considers the demand-related portion of production plant to be the minimum cost of providing the current system reliability level, and the remainder to be the energy-related portion.

Q: Has the Company found the peaker method to be reasonable?

A: Yes. The Company's current analysis of marginal generation cost is based on the same peaker method. In the case of the marginal cost calculation, a new combined cycle unit ("CC") is considered to operate as the baseload unit. The simple cycle combustion turbine ("CT") is a proxy for capacity costs. The excess of the cost of the CC over the CT is considered energy-related (Paice Direct at 12–13).

The Company's support for this methodology is a longstanding one, dating back to its 1989 UP&L Distribution Study at page 11:

> The increased cost of a baseload unit over a peaking plant represents an investment made to save fuel costs. The additional investment can be classified as energy related.… The generation plants have two equally important ratings, energy and demand.

Q: Please explain how the peaker method would be used to classify generation plant in a COS Study.

A: For each generation unit, a good initial estimate of the demand- or reliability-related portion of its cost is the cost per kW of a peaker (generally a simple-cycle combustion turbine) installed in the same period times the rated capacity of the unit. The cost of the unit in excess of the equivalent gas turbine capacity is energy-related.[4]

a) The Classification of Steam Plant

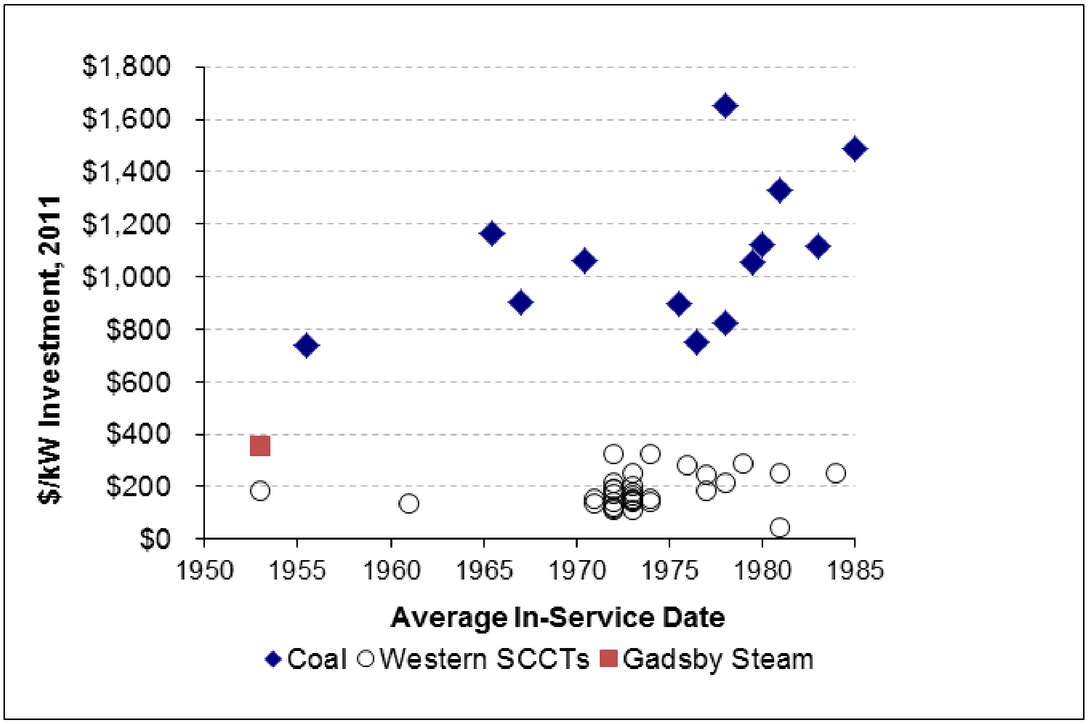
Q: Have you applied the peaker method to classify PacifiCorp's existing coal plants?

A: Yes. I compared the gross capital cost per kilowatt, as reported at year-end 2011, for each existing PacifiCorp steam plant and for contemporaneous combustion-turbine plants in the West, sorted by in-service date.[5] The peakers averaged about $170/kW, compared to almost $900/kW for PacifiCorp's coal plants, Figure 2 shows each plant's cost at year-end 2011. I include only data through 1986 (the in-service date of PacifiCorp's last coal plant) in Figure 2, and omit Blundell, which was built in two increments 22 years apart (which complicates graphing) and would require that the vertical scale be expanded to cover its cost of over $3,000/kW.

[4] This calculation overstates the reliability-related portion of plant cost: it assumes steam plant supports as much firm demand as would be supported by the same capacity of (smaller) combustion turbines. Higher forced outage rates, large maintenance requirements, and the size of large units all tend to reduce the contribution of large units to system reliability.

[5] Since PacifiCorp does not own any peakers built in the same period as its coal plants, I used as proxies peakers built in the relevant period in areas contiguous to PacifiCorp's service territories. The peakers are those owned by investor-owned utilities in Arizona, Colorado, Montana, New Mexico, Nevada, Oregon, and Washington, and were all built during the period 1970–1981.

Figure 2: Costs of PacifiCorp Steam Plants and Contemporaneous Western Simple-Cycle Combustion-Turbine Plants



Q: Does this comparison reflect the full energy-related portion of all steam plant investment?

A: Not necessarily. The FERC Form 1 data may not include all of the capital additions to test year gross steam plant, in particular some additional environmental-control investments that were not yet in service by end-of-the-year 2011.

Q: Have you analyzed the energy-related portion of test year steam plant?

A: Yes. I compared RMP's total gross steam plant in the test year (including the non-coal Gadsby and Blundell plants) with the total year-end 2011 costs of a representative mix of gas turbines.

Q: How did you derive the comparable gas turbine cost?

A: I matched each RMP steam plant with Western gas turbines built in the same time period. I calculated the comparable gas-turbine cost as the average cost per kW multiplied by the capacity of the steam plant.

I identified 59 simple-cycle combustion turbine ("SCCT") plants in the western states (Arizona, Colorado, Montana, New Mexico, Nevada, Oregon, Washington, and Wyoming) owned by investor-owned utilities that file the FERC Form 1 for which a current gross-plant value is reported.[6] For each year's vintage, I computed the capacity-weighted cost for that year's SCCT. For PacifiCorp steam plants that entered service in years for which I have no SCCTs added, I interpolated the costs of the last previous SCCT and the next SCCT.

[6] I did not look for California plants, because of the high cost of doing business in California. I also excluded any plants for which I could not distinguish simple-cycle combustion turbine plants from other technologies. In most cases, I had 2011 FERC Form data at 402–403, although in two cases I used 2009 or 2010 FERC Forms. For Sierra Pacific Power's 1961-vintage Tracy simple-cycle combustion turbine plants (sometimes called Clark Mountain), I used FERC Form data from 1999, the last year before Sierra Pacific added new, larger units to the plant.

Table 4: Cost of Western SCCTs Contemporaneous with PacifiCorp Steam Plants

			Contemporaneous Peakers				
			ISDs		*Gas $/kW*		
Plant	**Maximum MW** (PacifiCorp Share)	**Unit ISD**	Start	End	Start Year	End Year	Interpolated
Gadsby 1	60	1951	1953	1953	186	186	186
Gadsby 2	75	1952	1953	1953	186	186	186
Carbon 1	67	1954	1953	1961	186	134	179
Gadsby 3	100	1955	1953	1961	186	134	173
Carbon 2	105	1957	1953	1961	186	134	160
Dave Johnston 1	106	1959	1953	1961	186	134	147
Dave Johnston 2	106	1961	1961	1961	134	134	134
Naughton 1	160	1963	1961	1971	134	143	136
Dave Johnston 3	220	1964	1961	1971	134	143	137
Hayden 1	45	1965	1961	1971	134	143	138
Naughton 2	210	1968	1961	1971	134	143	140
Naughton 3	330	1971	1971	1971	143	143	143
Dave Johnston 4	330	1972	1972	1972	194	194	194
Huntington 1	445	1974	1974	1974	179	179	179
Jim Bridger 1	353	1974	1974	1974	179	179	179
Jim Bridger 2	353	1975	1974	1976	179	284	231
Hayden 2	33	1976	1976	1976	284	284	284
Jim Bridger 3	353	1976	1976	1976	284	284	284
Huntington 2	450	1977	1977	1977	191	191	191
Hunter 1	403	1978	1978	1978	213	213	213
Wyodak 1	280	1978	1978	1978	213	213	213
Craig 1	83	1979	1979	1979	291	291	291
Jim Bridger 4	353	1979	1979	1979	291	291	291
Craig 2	83	1980	1979	1981	291	148	219
Hunter 2	259	1980	1979	1981	291	148	219
Cholla 4	380	1981	1981	1981	148	148	148
Hunter 3	460	1983	1981	1984	148	249	215
Colstrip 3	74	1984	1984	1984	249	249	249
Blundell	23	1984	1984	1984	249	249	249
Colstrip 4	74	1986	1984	1995	249	497	294
Blundell Bottoming	11	2007	2006	2008	342	664	503
Total	6,384	**Total Cost for Contemporaneous SCCTs:**					$1,273M

Q: What were the results of this comparison?

A: For the test year, PacifiCorp reports its total gross steam plant to be $6.7 billion.[7] Contemporaneous gas turbines would have cost about $1.27 billion, or just 19% of total steam plant.

Q: Have steam-plant costs been rising recently?

A: Yes. In addition to the investments that would normally be required to extend the lives of aging coal plants, PacifiCorp and other owners of older coal-fired face a range of investments for environmental retrofits, including scrubbers, baghouses, and low-NOx burners. The plant additions in the test year alone amount to $496 million (Attachment OCS 3.6-2).

Q: How does the addition of pollution controls affect the portion of coal plants that is energy-related?

A: The pollution controls increase the cost of the coal plants, but not the cost of the demand-related peaker equivalent, and thus increase the share of the fixed costs attributable to energy.

Q: Is this result appropriate?

A: Yes. The purpose of pollution controls is to reduce emissions from the coal plants, to allow them to continue burning low-cost coal at high load factors. Peaking units that are only needed in a few high-load hours annually can afford to burn expensive clean fuels, and are often allowed to have higher emission rates, since they operate so little. Hence, need for the pollution controls is driven by the energy-serving function of the coal plants.

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[7] I computed this value from the $2.895 billion in Utah gross steam plant from the COS Study, divided by the 43.1547% SG allocation to Utah in the JAM.

Q: Has the issue of the classification of environmental retrofits been explicitly dealt with in the MSP process or in a Utah proceeding?

A: Not to my knowledge.[8] The classification of scrubber retrofits represents a new issue that requires Commission consideration.

Q: Are PacifiCorp's projections of new generation plant costs reasonably consistent with your findings from the costs of existing plants?

A: Yes. According to the 2011 Integrated Resource Plan, the lowest-cost new coal plant would be a Utah pulverized coal plant, at fixed costs of $296/kW-year. Netting out the fixed costs of a frame simple-cycle combustion turbine, at $89/kW-year, the energy-related fixed cost of the new coal plant would be $209/kW-year, or 70% of the total fixed cost. PacifiCorp's estimates of the costs of new SCCTs has increased significantly in recent years, and the energy-related share of a new coal plant based on those estimates has therefore declined. While the 70% energy classification of new coal from the IRP generally supports an energy classification much higher than the current 25%, the costs being allocated in this proceeding are those of existing plants, not hypothetical new plants.

Q: What do you conclude based on your peaker analysis of steam plant?

A: My computation above supports classification of 80% of steam plant and associated non-fuel expenses as energy-related and 20% as demand-related.

[8] I did address this issue in my testimony in Docket No. 10-035-124. However, the settlement stipulation, which the Commission accepted, made no changes to the COS methodology.

b) Classification and Allocation of Wind Resources

Q: Should the inter-jurisdictional allocation of generation plant constrain the allocation of wind resources?

A: No. Since 2006, PacifiCorp has added a significant amount of wind resources to its resource mix. To my knowledge, the issue of the classification and allocation of wind resources has not been explicitly dealt with in the MSP process.

Q: Has this issue been dealt with in any Utah general rate case?

A: Yes. In Docket No. 09-035-23, Division Witness Joseph Mancinelli recommended that wind-generation costs should be separated out from the remaining generation costs and allocated in the retail COSS based 100% on energy.

Q: What was the Commission's finding in that case?

A: The Commission ordered that the COS Study show a separate accounting for wind investment and related expenses, but retained the use of the F10 allocator.

Q: How should wind resources be classified?

A: I agree with Mr. Mancinelli that wind resources are acquired and built primarily to meet energy needs, and thus should be allocated primarily on energy. However, wind resources do have some capacity value that should be recognized for classification purposes.

Q: Has PacifiCorp estimated the capacity value of its wind resources?

A: Yes. According to its 2011 IRP at 87, Tables 5.5 and 5.6), the capacity contribution of PacifiCorp-owned wind plant is 12% and the capacity contribution of PacifiCorp wind purchases and exchanges is 15% of the total nameplate capacities.

Q: Based on PacifiCorp's estimates, how should RMP's wind resources be classified?

A: Since wind is twice the price of CTs per kW-year (see 2011 IRP, Table 6.5, Total Fixed Cost column), that means that only 6% of RMP's investment in wind is justified by its reliability contribution. The other 94% is energy-related.

c) Classification of Other Generation Resources

Q: How should the fixed costs of generation resources other than steam and wind be classified between demand and energy?

A: The Company's remaining generation resources are almost all hydro, combined-cycle combustion turbine ("CCCT"), and simple-cycle combustion turbine ("SCCT") plants.

For hydro, rather than attempting to determine the demand-related portion of fixed costs of these old plants (mostly from the first half of the 20th century) by comparison with a separate peaking technology, I use the traditional approach of considering the factor that drive the design of hydro plants. It is my understanding that Pacific Power and Light, prior to the 1989 merger, classified its mostly hydro-powered system 50/50 between energy and capacity. This classification makes sense, since the sizing of dams and reservoirs (and the related costs) are driven in large part by the need to store enough water to provide energy for many hours. Only about 20% of PacifiCorp's hydraulic production investment comprises turbines, generators and electric equipment. Some portion of the dams and reservoirs would also be needed to provide capacity. Thus, I use the 50/50 classification for hydro plant.

For combined-cycle resources, I used the Utah cost estimates in Tables 6.1 and 6.3 of PacifiCorp's 2011 IRP for the least-expensive SCCT and various existing CCCT designs. Table 5 compares the installed cost and total fixed costs for the various Utah combustion turbines.[9] Depending on the design and measure of cost, 7% to 21% of the CCCT's cost is in excess of the cost of the peaker. Overall, it seems reasonable to assume that the fixed costs of CCCTs are about 10% energy-related, based on PacifiCorp's IRP estimates.

Table 5: Costs of Simple and Combined-Cycle Combustion Turbines

	Base Capital Cost ($/kW)	Increase Over Peaker	Total Fixed Cost ($/kW-yr.)	Increase Over Peaker
SCCT Frame (2 Frame "F")	$991		$89.27	
Intercooled Aero SCCT	$1,174	15.6%	$111.76	20.1%
CCCT (Wet "F" 1x1)	$1,181	16.1%	$112.90	20.9%
CCCT (Wet "F" 2x1)	$1,067	7.1%	$98.04	8.9%
CCCT (Dry "F" 2x1)	$1,104	10.2%	$102.67	13.1%
CCCT (Wet "G" 1x1)	$1,117	11.3%	$100.78	11.4%

PacifiCorp's only SCCTs are the Gadsby peakers, which are LM6000 SPRINT intercooled aeroderivative gas turbines. Table 5 shows that about 16%–20% of the intercooled aeroderivative plant costs are above the costs of the pure peaking combustion turbine.

Even if the Gadsby peakers are treated as entirely demand-related, the weighted average of various components of the hydro, CCCT and SCCT costs are 24% to 29% energy-related. See Table 6.

[9]Hermiston and Chehalis appear to be 1×1 CCCTs, while Currant Creek and Lakeside are 2×1 CCCTs.

Table 6: Classification of Other Generation Fixed Costs

	Sub-Account	% Energy	
Non-Fuel O&M			
Hydraulic	$20,994,948	50%	
CCCT	$21,153,811	10%	
SCCT	$831,513		
Weighted Average			29%
Depreciation			
Hydraulic	$11,038,053	50%	
CCCT	$13,579,754	10%	
SCCT	$1,154,626		
Weighted Average			27%
Gross Plant			
Hydraulic	$364,478,545	50%	
CCCT	$522,079,728	10%	
SCCT	$34,771,758		
Weighted Average			25%
Net Plant			
Hydraulic	$253,348,365	50%	
CCCT	$439,502,520	10%	
SCCT	$24,252,813		
Weighted Average			24%

I therefore conclude that at least 25% of the fixed costs of generation other than wind and steam should be classified as energy-related, which is consistent with PacifiCorp’s treatment of these costs.

2. Allocation of Demand-Related Generation Plant

Q: How does RMP allocate demand-related generation plant?

A: It applies a 12-CP allocator. RMP has changed from a weighted 12-CP allocator (where the monthly weights are the ratios of monthly system peaks to the annual system peak) to be consistent with the jurisdictional method.

Q: Do you agree that this change in allocation is appropriate?

A: Yes. The unweighted 12-CP allocator is a better measure of how PacifiCorp peaks drive investment in G&T.

Q: How does the unweighted 12 CP allocator better reflect cost causation?

A: Weighting CPs by relative monthly peaks incorrectly assumed that the need for and cost of capacity is a simple function of the load at system monthly peak times. The significance of load in any given hour also depends on the following factors:

- the amount of generation capacity that is *available*, not just installed, to meet load in that hour. Because of forced outages, there are many hours that contribute to the system need for capacity.
- the scheduling of maintenance outages. PacifiCorp normally schedules generating-unit outages during the 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.
- the effect of retail load on PacifiCorp's ability to sell capacity in the wholesale market, including in the non-summer months. By reducing PacifiCorp's wholesale sales, the additional load increases net power costs.

3. Treatment of Firm Non-Seasonal Purchases

Q: How does RMP classify and allocate firm non-seasonal purchases?

A: The Company classifies firm non-seasonal purchases as 75% demand-related and 25% energy-related and allocates each month's cost separately based on class coincident peak and kWh usage in that month.

Q: What costs does the Company's COS Study include in the category of "firm non-seasonal purchases"?

A: As shown in the COS Study Model sheet labeled "NPC," the category is comprised of all purchases except non-firm and seasonal. It consists of the following transactions:

- long-term firm purchases,
- short-term firm purchases,
- storage & exchange,
- system balancing purchases.

The last two transaction categories are clearly 100% energy-related.

Q: Does RMP's COS Study understate the energy-related portion of long term firm purchase costs?

A: Yes. RMP allocates purchases and generation inconsistently. In the case of its own generation plant, RMP treats fuel costs and plant costs separately, and classifies fuel as 100% energy-related, and plant as 75% demand–related and 25% energy-related. However, in the case of firm non-seasonal purchases, RMP does not attempt to separate the variable and fixed components and instead treats all purchases costs as fixed plant costs. As a result, RMP allocates only 25% of all purchase costs, including fuel costs, on energy. This difference is illustrated in Table 7.

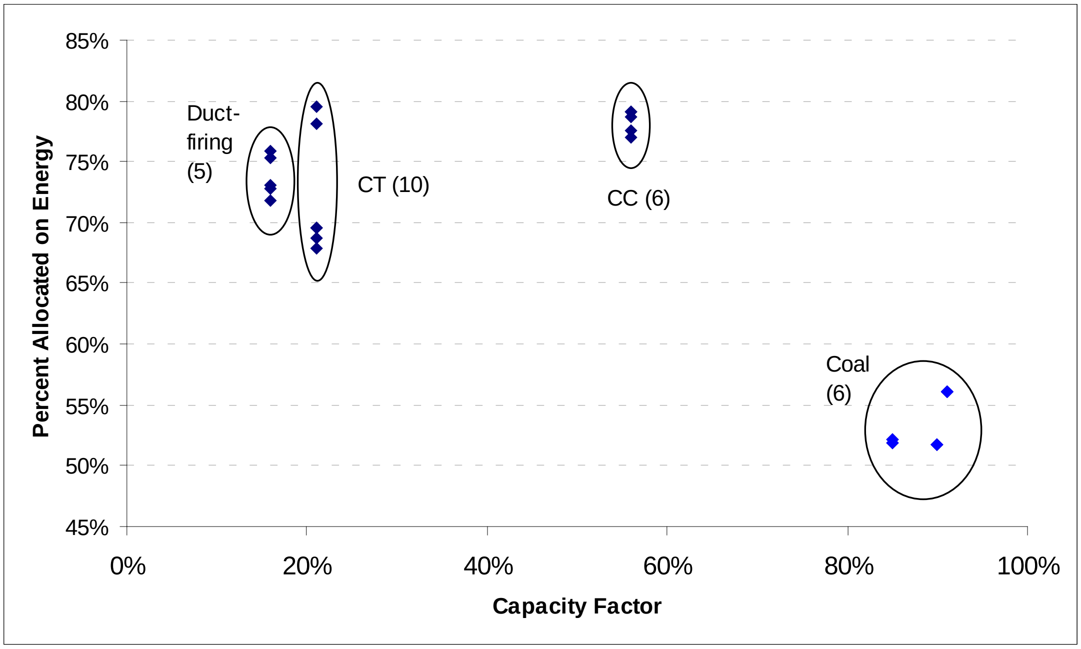
Table 7: Share of Cost Allocated on Energy

	Fixed Costs	Fuel and Variable Costs	Total if Half of Cost Is Fuel
Plant	25%	100%	62.5%
Non-Seasonal Purchases	25%	25%	25.0%

Q: How significant is the disparity between RMP's classification of purchases and generation?

A: The disparity is large. From PacifiCorp's 2011 Integrated Resource Plan, I computed the portion of total costs that RMP would allocate on energy for each potential new resource (See Figure 3). The energy-related portion of the costs is the sum of variable costs plus 25% of fixed costs. The portion of generation costs allocated on energy under RMP's current classification and allocation method ranges from 53% for pulverized coal with carbon capture and sequestration to 61% to 69% for various types of combustion turbines, to 75% for various combined-cycle configurations.

Figure 3: Energy-Related Share of New Resource Costs under the Company's Cost-of-Service-Study Approach



Q: What do you conclude from comparing the classification of purchases versus plant resources?

A: Reclassification of purchases as 50% demand-related and 50% energy-related would be consistent with RMP's resource mix and current classification methods for generation costs, based on the 75%-demand-to-25%-energy split applied to fixed generation costs and the 100% energy classification of fuel. If the Commission adopts more-realistic classification of plant costs, the classification of purchases should be updated.

C. Allocation of Service Drops

Q: How does the Company allocate service lines?

A: The Company allocates service lines on weighted customer number, where the weights are calculated from the cost of a new service by type of customer (Exhibit RMP__(CCP-3), Tab 1, at 9).

Q: Does the derivation of this allocator take into account all of the important cost factors?

A: No. the Company's derivation of the allocator has at least the following two problems:

- It ignores the sharing of services by customers in multi-family buildings,
- It assumes the same average service length (70 feet) for all rate classes.

Q: How does the allocator ignore sharing of services?

A: It assumes that each residential customer requires its own service line (Paice Direct at 6).

Q: Has RMP confirmed that some residential customers share services?

A: Yes. In his Direct Testimony, Mr. Paice agrees that some residential customers do share service drops. However, RMP has not modified the services allocator to correct this error.

Q: What is the Company's explanation for continuing to rely on an invalid assumption?

A: According to Mr. Paice (Direct at 6), RMP is unable to correct its services allocator because "Company records do not contain data regarding the number of customers per service drop." In addition, in the Company's view (as stated in response to DR OCS 7.6 in Docket No. 10-035-124), a single adjustment for the number of residential services is inappropriate for the following reasons:

- Multi-family building service drops are more expensive than single-family services and there are no “clear rules of thumb” for deriving a representative cost figure.
- Some general service customers may also share service drops.

Q: Have you estimated what the impact of shared services would be on the residential services allocator?

A: Yes, given the data I have available to me. Preliminary results from the 2010 Census of Housing indicates that about 29% of housing units in the Utah counties that RMP serves are in multi-family structures.[10] Of those, 13.2% of RMP’s customers live in housing structures with two to nine units, and 11.5% live in structures with more than nine units.

Depending on the number of units in each category sharing services, the total number services to residential customers may be 20% less than RMP assumes for allocation purposes. See Table 8.

While multiple customers would require larger shared services, this effect offsets only a small part of the reduction in number of services. Table 8 also shows the effect of conservatively high cost multipliers for multi-customer services, using the relative costs of single-phase overhead services from IR OCS 3.17. (The cost ratios for underground services are smaller.) With this conservative adjustment, the cost of services would be no more than 82.5% of the cost derived from PacifiCorp’s analysis.

[10]In calculating the average mix of housing type, I weighted each county’s mix by the number of RMP customers in that county (from OCS 3.18).

Table 8: Estimate of Residential Sharing of Service Drops

Units in Structure	Number of Units	Customers per Service	Relative Service Cost
1-unit, detached	509,504	1.00	1.00
1-unit, attached	36,778	0.75	1.075
2 units	29,248	0.50	1.15
3 or 4 units	36,219	0.29	1.44
5 to 9 units	28,405	0.15	1.61
10 to 19 units	31,255	0.07	2.90
20 to 49 units	23,921	0.03	6.65
50 or more	24,063	0.02	6.65
Total RMP housing units	719,392		
Number of residential services		569,982	
Average number of services per residential customer		0.793	
Weighted residential services			593,656
Weighted equivalent serves per residential customer			0.825

Q: **Does this result differ much from the results you computed with final 2010 Census data?**

A: No. The final 2000 Census data on housing structures also produced an estimate of 0.79 services per customer. Using the 2010 data in the calculation has not significantly changed my estimate of average number of services per residential customer.

Q: **Does RMP derive all COS Study allocators from actual data in Company records?**

A: No. Essentially every allocator in a COS Study is based on estimates or forecasts, including RMP's calculation of the unit cost of a service drop by customer class.

Q: **Is your use of census data to derive an adjustment to the number of shared services a reasonable basis for a services allocator?**

A: Yes. The use of census data is clearly an improvement over RMP's assumption that every residential customer has its own service drop.

D. Summary of Cost-of-Service Corrections

Q: Please summarize your corrections to the Company's COS Study.

A: Table 9 summarizes the rate-of-return index for each class, for

1. the Company's proposed rates and COSS;
2. each of the four adjustments I propose in the COSS:
    - classification of 94% of wind costs as energy-related,
    - classification of 80% of steam fixed costs as energy,
    - classification of 50% of purchased power as energy, and
    - correction of the services allocator to reflect sharing of services, so that the portion of service costs allocated to the residential class is reduced 17.5%;

and the combination of my four adjustments.

I derived my adjusted results by modifying the COS Allocation Options sheet (and other inputs, as required) in the Company's cost-of-service model.

The effect of these four corrections is to raise the residential index from 0.93 to 1.03, slightly raise the indices for Schedules 6 and 23, and reduce the indices for all other schedules.

Table 9: Rate-of-Return Index—RMP Proposed and Corrected

		Adjusted for				
Schedule (Number)	**RMP Proposed**	Wind	Steam	Purchased Power	Shared Services	**Combined**
Residential (1)	0.93	0.95	0.98	0.95	0.94	1.03
General Service, Large (6)	1.18	1.19	1.20	1.19	1.18	1.20
General Service, Over 1 MW (8)	1.06	1.04	1.01	1.04	1.06	0.98
Street & Area Lighting (7, 11, 12)	1.72	1.62	1.49	1.65	1.72	1.34
General Service, High Voltage (9)	0.77	0.73	0.67	0.73	0.77	0.60
Irrigation (10)	0.79	0.77	0.74	0.77	0.79	0.70
Traffic Signals (15)	1.03	1.00	0.96	1.00	0.94	0.83
Outdoor Lighting (15)	2.65	2.37	2.06	2.50	2.62	1.71
General Service, Small (23)	1.24	1.25	1.27	1.25	1.22	1.27
Customer 1 (SpC)	0.47	0.43	0.36	0.42	0.47	0.28
Customer 2 (SpC)	0.46	0.34	0.14	0.29	0.46	(0.08)

IV. Marginal-Cost Study

Q: What changes did RMP make to the marginal-cost study filed in this case?

A: It appears that the only change since 10-035-124 is an updated estimate of the customer-related portion of line-transformer costs, which was prepared to support RMP's customer charge proposal.

Q: Did you review RMP's Marginal Cost Study in Docket No. 10-035-124?

A: Yes.

Q: Have you identified any problems with RMP's estimate of marginal transmission costs?

A: Yes. As I discussed in my testimony in Docket No. 10-035-124, the Company includes less than one third of its projected transmission expenditures as load-related. While transmission is sometimes required due to drivers not directly related to load, such as the integration new generation, this ratio of load-related-to-total generation is very low. In Docket No. 10-035-124, RMP failed to provide a justification for the exclusion of so much of the planned transmission. Indeed, RMP's discussion of the excluded projects indicated that most of them were related to increasing capacity, and so should be considered load-related.

Q: Are there similar problems in the derivation of marginal distribution costs?

A: Yes. The Company's estimates of marginal distribution pole and conductor costs are not based on a marginal analysis of the investments required per megawatt of load growth, but on the average cost of a developed system, with identical circuits (represented by one "hypothetical" circuit) and balanced loads on each branch of the circuit (Workpaper PC-7 within the Marginal-Cost Study). Since small amounts of load growth can require the addition of a new feeder, the reconductoring of an existing feeder, or an increase in feeder voltage, RMP's use of the average costs of serving a hypothetical system is a poor approximation of marginal costs.

In addition, RMP treats the entire cost of single-phase conductors as being customer-related, along with the equivalent cost per mile for the three-phase branch conductors, even though the sizing of single-phase and three-phase conductors is related to load.

Similarly, PacifiCorp's estimate of marginal distribution substation costs are not based on the investment over a period of time, divided by the growth of distribution load. Instead, PacifiCorp estimates the marginal cost in dollars per MW by dividing the projected investment by the MVA capacity of the transformers added. That assumption understates the marginal substation cost, since substation capacity in MVA is always higher than customer load in megawatts, for the following reasons:

- Each MW of customer load imposes more than one MVA of load, unless power factor happens to be 100%.

- There are losses in the distribution system from the customer to the substation.
- Substation transformers come in discrete increments, so each a small increment in load (a megawatt or less) can require the addition of 10 or 20 MVA of substation capacity.
- Substations include back-up capacity, to cover outages of other transformers in the same substation, as well as outages of other transformers and failure along looped feeders.

Based on some regression analysis for line transformers, the Company concluded that only 18% of residential transformer costs are load-related (Workpapers XFMR-1 and 2).

Q: What is the basis of RMP's classification of transformer costs into customer and demand components?

A: The Company used a regression analysis to estimate the minimum installed cost of a transformer based on the Zero-Intercept Method.

Q: Please describe the Zero-Intercept Method.

A: The Zero-Intercept Method attempts to extrapolate from the cost of actual equipment (including actual minimum-sized equipment) to the cost of hypothetical equipment that carries zero load, as in 0-kVA transformers. The idea is that this procedure identifies the amount of equipment required to connect existing customers, even if they had virtually no load.

Q: Can the Zero-Intercept Method be relied on to determine the customer-related portion of transformers?

A: No. A system designed to connect customers but provide zero load would look very different from the existing system.

A zero-capacity electric system would not use the overlapping primary and secondary systems and line transformers that the real system uses. A system with very low loads would use a single distribution voltage, eliminating the need for most or all line transformers. Traditional copper telephone distribution systems, for example, serve many thousands of customers without comparable step-down transformers.

In reality, the number of transformers, as well as their size, is determined by load.

The zero-intercept method is so abstract that it can be interpreted in many ways, and can produce a wide range of results. Any use of this method must be grounded in a firm understanding of the purpose and conceptual framework for defining a zero-intercept.

Q: How did the Company apply the Zero-Intercept Method?

A: The Company used a regression analysis to estimate a relationship between transformer size (kVA) and installed cost. By extrapolating from the regression line to the zero intercept, the Company determined the hypothetical total "cost" of all zero-kVA transformer to be $3,625.25 times the number of residential transformers, assuming that each zero-intercept transformer would serve only 6.07 residential customers.[11]

Q: Assuming line transformers *would* be installed in a very-low-usage system, has RMP properly interpreted the results of its regression analysis?

A: No, for several reasons. First, the regression results do not make sense. The zero-intercept exceeds the cost of a quarter of all transformers and a third of all

[11]Since this estimate is based on the Company's estimate of the cost of new transformers, the Company adjusts the customer-related portion so the total transformer cost is consistent with the residential allocation in the COS Study.

single-phase transformers in the regression data set. RMP's estimate of the customer-related portion of transformer costs assumes that the hypothetical utility would install zero-capacity transformers to serve zero-load customers that cost 27% more than 10 kVA transformers and 16% more than non-pad-mounted 25 kVA transformers (Attachment OCS 3.38).

Second, the Company assumes that the zero-kVA transformer could serve only 6 customers with zero load. If the customers all had zero loads, there would be virtually no limit on the number of customers that could be reached by lines from a single transformer.

Q: Have you identified specific problems with RMP's transformer regression analysis?

A: Yes. The regression analysis that RMP used to estimate the zero intercept (documented in Attachment OCS 3.38) has at least the following problems:

- The regression is based on synthetic data, rather than the actual installed cost of actual individual transformer equipment.
- The "data set" includes three-phase transformers that are not used to serve residential customers and do not belong in an analysis of residential transformer costs. Of the 24 transformer sizes and types represented in the "data set" only ten, at most, are used for residential purposes.

Q: In what way is the regression analysis based on a synthetic data set?

A: The regression "data set" appears to consist of 24 numbers, each of which represents some sort of estimate of installed cost by size and type of transformer. By relying on averages and simple formulas, the analysis has removed from the data set most of the cost variation that is supposed to be dealt with in a statistical analysis.

Then, without actually adding pertinent information, the Company increases the number of “observations” from 26 to 4,499. It does so by treating each of the 24 “data points” as though it represents many transformers of a single size at the same cost.

Q: Does RMP’s Marginal-Cost Study provide any useful guidance for rate design?

A: Yes. Since the study is likely to have understated the cost of load growth, RMP’s estimates of marginal energy cost plus demand cost provide a minimum target for the tail block charges of non-demand rate schedules. The actual marginal demand costs may be greater.

The estimate of marginal customer costs, on the other hand, is not valid and should not be relied upon in setting the level of the residential customer charge.

V. Recommendations

Q: Please summarize your recommendations regarding the load data used in the Company’s COS Study

A: I recommend that the Commission order the Company to eliminate its calibration of load data. Instead of calibration, I recommend that the Company modify its load research methods to reduce inconsistencies in its approach to forecasting jurisdictional and retail-class peaks. In particular, RMP should take the following steps:

- base both the jurisdictional and the retail class energy and peak forecasts on weather-normalized load data,
- estimate the losses included in Utah for the JAM that may be due to wholesale transactions and interstate transfers,

- develop normalized long-term estimates of irrigation loads.

Q: Please summarize your recommendations regarding COS-Study classification and allocation.

A: I recommend that the Commission endorse the following changes in the Cost-of-Service Study:

- classify at least 80% of steam plant and associated expenses as energy-related,
- classify 94% of wind plant and associated expenses as energy-related,
- classify at least 25% of other resources (SCCT, CCCT, and Hydro) and associated expenses as energy-related,
- classify at least 50% of non-seasonal firm purchases as energy-related,
- recognize the sharing of service drops by residential customers in multi-family dwellings.

I also recommend that the Commission accept the allocation demand-related generation plant on an unweighted 12-CP factor, an improvement the Company has introduced in this current filing.

Q: Please summarize your recommendations concerning residential rate design.

A: The marginal-energy-plus-demand-cost estimates included in the Company's Marginal-Cost Study provide a reasonable minimum target for the tail-block charge for the residential class. However, the Company's estimate of marginal customer costs is not valid and should not be relied upon in setting the level of the residential customer charge.

Q: Does this conclude your testimony?

A: Yes.