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	)))))))))	**DOCKET NO. 11-035-200** **DPU Exhibit 8.0 DIR-COS**

COST OF SERVICE

DIRECT TESTIMONY OF LEE SMITH

ON BEHALF OF

THE UTAH DIVISION OF PUBLIC UTILITIES

June 22, 2012

I. INTRODUCTION

Q. What is your name and business address?

A. My name is Lee Smith, and I work for La Capra Associates, One Washington Mall, Boston, MA 02108.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Utah Division of Public Utilities (Division).

Q. Please describe your background and experience.

A. I am a Managing Consultant and Senior Economist at La Capra Associates. I have been with this energy planning and regulatory economics firm for 28 years. I have prepared testimony on gas and electric rates, rate adjustors, cost allocation and other issues regarding more than 40 utilities in 21states and before the Federal Energy Regulatory Commission. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level. My resume is attached as DPU Exhibit 8.1 DIR-COS.

Q. Please describe your educational background.

A. I have a bachelor's degree with honors in International Relations and Economics from Brown University. I have completed all requirements except the dissertation for a Ph.D. in economics from Tufts University.

Q. What is the purpose of your testimony?

A. I have been retained by the Division to review and analyze the cost allocation and rate design presented by Rocky Mountain Power ("the Company"). I have developed a cost allocation study which reflects the Division's revenue requirements as a basis for determining class revenue requirements. The Division's rate objectives and class revenue requirements then become the basis for rate designs, which I will also present.

Q. Please summarize your testimony.

A. I have reviewed and analyzed all aspects of the Company's allocation of costs to customer classes and proposed class rates. Regarding the cost of service study, I will first address the issues raised by the Commission in its Action Request of May 17. I then address a number of other issues related to the Company's allocated cost of service study. I address rate design issues including the Company's load research and its estimation of peak loads, the Company's calculation of customer costs, and the Company's marginal cost study and a proposed rate design. I have reflected the Division's revenue requirement adjustments in the cost of service model and reflected my recommended allocation changes in that model. Finally, based on the above analyses, I recommend an alternative rate spread.

I have found that:

- There are a number of problems in the allocated cost of service study

- Correcting the problems that I have identified results in finding lower deficiencies to the residential class and to Schedule 6, although these changes are not major
- The load research/ load forecast is imperfect, particularly regarding the Irrigation class loads
- The Company's proposed increase in the residential customer charge is not warranted
- The Company has not attempted to base its Time of Use rates or its rate components on marginal costs
- The way in which the Company's model treated working capital, interest and income taxes is inconsistent with the JAM model and inconsistent with the depiction of the full cost of serving each class
- The increases to customer classes can be based on the results of the cost of service study, with mitigation for classes that would otherwise receive particularly high increases

Q. There appear to be a number of issues with regard to the estimation of class costs and rate design. How have you presented tabular information regarding these various issues?

A. The first cost of service modifications that I show have been made in a modification of the model distributed by the Commission that I am referring to as "Model X." This produces results almost identical to the Company's model but is easier for the analyst to use. Allocation changes contained in Model X are applied to the Division's recommended revenue requirement. I then show the changes from these results to those resulting from changes to the Company's model's treatment of working capital, interest and income taxes. I then utilize the results of this model as a basis for computing rate spreads and rate design.

II. ALLOCATED COST OF SERVICE STUDY

Q. What have you reviewed with regard to RMP's allocation of costs?

A. I have compared the allocations between states and the allocations of the same cost categories within Utah classes. I have also critically reviewed the Utah allocation methodologies. There are a number of aspects of the Company's allocation which warrant discussion and in some cases correction.

A. Response to the Commission's Action Request on Inconsistencies between Jurisdictional and Intrastate Allocation Methodologies

Q. Have you prepared the Division's response to the Commission's Action Request of May 17?

A. Yes. The Commission on May 17 asked the Division to respond to several issues arising from the integrated cost of service model. These issues were framed as three inconsistencies between the Company's jurisdictional and class cost of service studies: 1) relations among cash working capital, interest expense, and income taxes; 2) the determination of state income taxes; and 3) use of the income to revenue multiplier.

Q. Would you please summarize these differences?

A. On a fundamental level, the jurisdictional cost of service study calculates cash working capital, interest expense, and income taxes based on the underlying allocations of rate base and expenses to each jurisdiction. In contrast, the intrastate Utah treatment allocates these cost elements to rate classes based only on earned income amounts before taxes. From a very simple perspective, this means that when the cost of service determines that a class earns below the average rate of return, the amount of working capital, interest expense, and income taxes that are attributed to the class are less than they would be if the class earned the average rate of return. The opposite is also true; if a class earns above the average rate of return, it is allocated more of these costs than it would pay based on the average rate of return.

The results of the Jurisdictional Allocation Model ("JAM") are that each state's cost of service is represented as allocated expenses, plus the return on allocated rate base, working capital, interest expense, and income taxes[1] that are calculated relative to the required return, which as noted is dependent on allocated rate base.

The intrastate allocation is inconsistent with the JAM allocation and does not reflect an allocation of all costs, as it results in reported class cost of services that do not include

[1] State income taxes involve another issue which will be discussed separately.

working capital, interest expense, and income taxes that are related to the return that is allocated to them.

Q. Do you recommend changes to the Company's allocation methods regarding these issues?

A. Yes. Modifying the treatment of working capital, interest expense, and income taxes will result in a more complete estimate of the full cost of serving each customer class, and will be consistent with the JAM allocations. These issues have been discussed in technical sessions. The model distributed by the Commission has been modified so that it does calculate full costs, by allocating the above cost elements consistent with the JAM model. As mentioned above, I am referring to this modified model as Model X.

Q. Do all of the tables that you use to illustrate cost of service depend on this revised model?

A. No. In order to illustrate changes from the Company's filed cost of service that result from my recommended allocator changes, my Tables 3 to 6 compare my results to those of the Commission model. Subsequently (Tables 10 and 11), I show changes to class deficiencies resulting from Model X, both with my allocators and Division revenue requirements.

B. Consistency Between Utah and JAM Allocations

Q. Are the allocators that RMP has used in its Utah class cost of service study the same as those used in its JAM?

A. Most the allocators are the same. One significant change is that in the previous case the 75% of the generation capacity allocator was based on weighted 12 Coincident Peaks. Each month was weighted by its relationship with the highest monthly peak, which put more weight on high load months. The JAM allocation of generation capacity uses unweighted 12 CPs, and in this case the Company has switched back to using the same demand definition for the jurisdiction allocation as for the JAM allocation.

Q. Why should most JAM and Utah allocators be similar if not identical?

A. The JAM allocators for generation and transmission determine the Utah jurisdiction's generation and transmission costs. It would be undesirable to communicate something radically different to Utah customers in the Utah cost of service study. However, if conditions have changed such that some JAM allocators no longer reflect cost causation, and using JAM allocators provide erroneous price signals to different customer classes, an argument can be made for adopting a different allocator within Utah.

Q. Do you believe it is appropriate that some Utah allocators are different from the JAM allocators?

A. The short answer is yes. RMP's distribution costs are dominated by Utah specific distribution plant, so allocation decisions are specific to Utah. Also the allocation of a number of costs related to customer service may be different, because to distinguish between classes within Utah requires a different approach than allocating between jurisdictions. Where cost causation between Utah and the other states and between customer classes within Utah is different, different allocators will be appropriate.

Q. Are the purposes of inter and intrastate allocation the same?

A. No, they are not. The JAM allocation determines what portion of PacifiCorp costs, primarily generation and transmission costs, will be paid by each state. The intrastate or interclass allocation is a basis for determining how much different classes will pay, and therefore also underlies rate design. There are a number of accounts whose Utah class allocation I would not recommend changing, even though they may seem to differ from the JAM allocation.

<u>C. Allocation of Generation and Transmission Plant and Expenses</u>

Q. How has RMP allocated generation and transmission capacity costs in the Utah cost of service study?

A. Generation and transmission fixed costs are allocated using the same allocator used in the JAM allocation, allocator F10. This allocator weights a measure of demand by 75% and energy by 25%; in other words, 75% of these fixed costs are "classified" as demand. The measure of demand is the average class 12 monthly peaks coincident ("12 CP") with the monthly peaks of the entire PacifiCorp system. In the previous case the Company's filing utilized a different measure of demand, in which the 12 CPs were weighted by their relationship to the peak month. The change was made to be more consistent with the JAM allocation. The allocation of these fixed costs to customer classes is dependent on both the classification, (the weight placed on demand and energy), and on the definition of demand. In other places and times demand has been defined by a single coincident peak, an average of summer peaks, and an average of summer and winter peaks.

Q. Do you think the Company had strong justification to move back to using the unweighted 12 CP in Allocator F10?

A. Yes. The MSP process and prior Utah orders supported the unweighted 12 CP measure for demand and a 75% weight for demand. There has been no analysis demonstrating why these decisions, particularly the adoption of a 12 CP definition of demand, should be modified. In addition this results in consistency between intrastate and interstate allocations, since Utah's cost responsibility for generation capacity is determined by the use of the 12 CP demand.

Q. Has this allocation methodology, that is the 75/25 classification and the definition of demand as 12 CPs, been supported by current analyses of cost causation for all generation and transmission plant in this case?

A. This method was proposed and accepted by the Commission in Docket No. 97-035-01. In 09-035- 23 Mr. Paice described the methodology as the result of a studies producing a result suitable to all parties, since at the time of the Utah Power – Pacific Power merger both companies had used different methodologies. (p. 8 Rebuttal) There was a Division finding supporting the use of 12 months of coincident peaks, and also a finding that energy plays some role in the selection of least-cost resources. Mr. Paice stated that the 75/25 split was retained during the Multi-State Process discussion because it fell ("in the middle of the range of reasonable approaches." (p. 9 Paice Rebuttal) This was a qualitative position rather than a quantitative analysis of portfolio planning. It is also significant that Division support of this methodology 15 years ago did not conclude that the methodology best reflected cost causation, but merely, as cited by Dr. Powell, that the evidence was "not inconsistent" with the methodology.

In this case there has been no analysis to demonstrate the appropriateness of this methodology for application to the present loads and generation portfolio. The Company did refer to a "stress analysis" as providing support for the 12 CP definition of demand. This analysis is not current and it is not clear how it results in the conclusion that all 12 months contribute to the need to add capacity to meet peak loads. Dr. Powell also discusses this topic in his testimony.

Q. Have there been changes in the major reasons for generation capacity investment that suggest that the allocation of generation capacity costs should be reviewed?

A. Yes. There has been a significant shift in the Company's generation portfolio since 1997, as a very large quantity of wind generation has been added. The current book value of PacifiCorp's wind capacity (including contracts) is 22% of total production capacity, while that percentage in 1997 was probably zero. (The 2011 IRP shows no wind capacity that had been in place in 1997). PacifiCorp's Load and Resource rated wind capacity is 23.5% of its total nameplate rated capacity according to the 2011 IRP. [2]

Q. Why is the proportion of wind capacity in the generation portfolio relevant?

A. If we reviewed each generation plant type separately, we would conclude that the classification of costs between demand and energy varied with each type of plant. Peaking units, for instance, are built primarily to meet demand peaks, and are also the least capital cost means of meeting additional peak loads. Utilities invest in more expensive generating units because the additional expense is justified by the energy savings that will result from more capital intensive units. For instance, a large portion of the cost of coal units is justified by energy savings, and only a small portion of investment in coal would be directly related to demand.

The 75/25 classification method was found reasonable based on the mix of generation plant in the generation portfolio that existed 15 years ago. If the portfolio at that time had included much wind power, the classification that was adopted would probably have been different.

Wind generation is built in order to supply cheap energy and/or to meet state requirements for renewable power. Requirements for renewable power are also driven by concerns about energy costs and emissions resulting from energy production. The amount

[2] 132 MWs of L&R wind /1032 MWs nameplate wind capacity 2011 IRP Table5.5

of wind required by state Renewable Portfolio Standards is expressed in terms of the percent of energy that should result from renewable resources. As a result, the primary cost causation factor for wind energy is energy. Wind normally gets very little capacity credit, as it is not guaranteed to be available at the times capacity is needed to meet load and reserve requirements. The generation portfolio that resulted in the 75% demand allocation accepted in 1997 did not reflect the 18% of production rate base, or the 23.5% of total capacity in the portfolio today that should be allocated primarily on energy.

Q. How have you determined what portion of the cost of wind capacity you recommend classifying as and allocating by capacity?

A. I first referred to the Company's 2011 Integrated Resource Plan. Table 5.5 contains the total amount of PacifiCorp installed capacity and also Resource and Supply Contribution of those wind resources. While the relationship between total capacity and the amount of capacity credit produced by wind resources varies, on average it was 12%. In other words, on average 100 MWs of wind capacity is only considered to contribute 12 MWs to PacifiCorp's capacity target. However, the capacity cost per MW of wind is higher than the cost of peaking units, so the 12 MWs are more expensive than what is normally considered peaking capacity. In addition, wind resources require wind integration costs, and in general do not provide some of the useful characteristics provided by less expensive peaking capacity. As a result, I recommend discounting the capacity value of wind by as much as 50%. A 50% discount results in a 6%/94% demand/ energy classification for wind resources.

Q. How do you respond to the fact that your recommendation will result in an inconsistency between classifying wind capacity cost as 94% energy when the JAM method classifies only 25% of this cost as energy?

A. First, as I noted above, the JAM method was developed and adopted when there was essentially no wind in the portfolio mix. Second, other PacifiCorp's jurisdictions' intrastate allocations also deviate from the JAM allocation (and classification) of generation capacity. Presumably regulators in other states have adopted intrastate allocations that they believe respond to their rate design goals better than the JAM allocation would. Third, I believe this revised allocation will produce a more equitable intraclass allocation. The revised class allocation will not impact interstate allocation unless and until a change is adopted at the MultiState level.

Q. Which other PacifiCorp jurisdictions allocate generation capacity costs to customer classes in different ways?

A. Oregon and California essentially classify and then allocate generation capacity by first estimating marginal costs by function, then reconciling marginal generation costs to embedded generation function revenue requirements. This is equivalent to a classification that is based on the cost relationship between a peaker (simple combustion turbine) and a baseload (combined cycle unit) and then an allocation of the demand portion on class loads coincident with the system peak. Washington classifies 35% of generation capacity as demand, 65% as energy, and allocates the demand portion on 100

Summer and 100 Winter System Peaks. The difference from the JAM generation plant methodology evidently is based on the assumption used in Washington that the cost of peaking capacity is determined by the Bonneville Power Administration contract capacity. Only Wyoming and Idaho classify and allocate generation capacity in the same manner that RMP does.

Q. The Commission in its order in 09-035-23 stated that parties proposing changes to approved methods should demonstrate that the changed method is "appropriate" and "viable at the interjurisdictional level." Please respond.

A. I think that allocating 94% of wind capacity on the basis of energy is both an appropriate and viable method.

I have established above that classifying a large portion of wind resources on the basis of energy reflects cost causation and is appropriate from that standpoint. In addition, I believe it is appropriate to modify allocation methodologies to reflect significant changes in the underlying costs.

By "viable", the Commission seems to have asked what impact this change at the MSP might have on other states and whether it is likely that they would agree to this change. I would expect that states with mandatory RPS standards should be aware that these change generation portfolios and change cost causation. How they react to this probably will be influenced by the actual dollar impact to them. States with higher energy use compared to the sum of their 12 Coincident peaks will be allocated more generation capacity costs, and those with lower energy use will be allocated less. However, this change will apply to less than twenty percent of PacifiCorp's generation rate base. In addition, if the definition of demand were also reviewed, this might offset some of the changes due to a change in classification. I have estimated that this change might result in a range of changes in total allocated costs of between 0.2% decreases to 0.3% increases (with a 0.01 % decrease to Utah).

D. Allocation of Distribution Plant and Expenses

Q. Are there any problems with RMP's allocation of distribution plant in the Utah cost of service study?

A. Yes, I believe there are. A major problem that has persisted is the allocation of service plant. Service plant is allocated to customer classes as if each customer requires an individual service. It is clear many residential customers do not have individual services. While there may be some Schedule 6 customers who share services, it is the overstatement of residential services that has been the major concern.

Q. Has the allocation of services been an issue in prior cases, and how has RMP responded to this issue?

A. Yes, it has been an issue in a number of prior cases. The OCS attempted to "correct" this in 10-035-124, and both the OCS and the Division recommended that cost allocation reflect the impact of multifamily housing. Although the Division witness in 10-035-124, Dr. Abdulle, did not assert that he had an exact or "proper" estimate of the number of residential services, he did testify that the overallocation of service plant could be substantial and an adjustment should have been made to reflect this possibility.

The Company has implied that it would require a major study to identify shared services, and it would need approval to do such a study. (97-035-23 Paice Rebuttal p. 6) I believe that the Company could have addressed this issue by analyzing a sample of its data, but it has not done so. Mr. Paice dismisses the relevance of the Division testimony in the last case because the case was settled. The Company did no further analysis of its system before filing this case, although in its revised response to OCS 3.19 it indicates that it now knows how many customers are in multifamily dwellings. While it is true that there may not have been exact data on the number of residential services, there are many aspects of the cost allocation process that are not exact. It is unrefuted that there are fewer residential services than there are residential customers.

Q. Is there additional data that can be used to estimate a correction to the service plant allocation?

A. Yes. Additional data that has been provided in this case on numbers of multifamily customers, on the cost of service plant, and the number of customers served by transformers, that is all relevant to the issue. Also, the results of the 2010 U.S. Census are now available.

Q. What does the data on multifamily numbers of customers indicate about residential services?

A. Customers living in multifamily housing will almost always share services. For all customers who share services with other customers, the Company's service allocator overstates the number of residential services. According to the revised response to OCS 3.19, there are 158,779 residential customers identified as located in multifamily units. These will range from two family units to apartment buildings with more than fifty customers. The most conservative way to use this data is to make a computation assuming that all of these multifamily customers share a service with one other customer. I will call this Method 1 for adjusting the service allocator. It results in a finding that at a minimum the number of services will be 79,390 less than the number of customers.

Q. What does the transformer data indicate about multifamily customers?

A. Detailed data on transformers provided in response to OCS 3.15 shows the number of residential customers served by each specific residential transformer, which ranges from one to 239 residential customers. This data does not directly identify all customers who may be sharing services, since residential transformers that are not serving multifamily units still typically serve from 3-6 individual housing units. However, there is a practical maximum number of individual units that are served by individual transformers.

For the transformer method approach, which I have called Method 2, I have assumed for this estimate that a transformer of 100KW will serve no more than 20 residential customers. I reviewed the data and identified the number of transformers that served more than 20 residential customers, and the total number of customers served by these large residential transformers. I further assumed that these multifamily units were served by only one service. Method 2 results in an alternative estimate of the overstatement of the number of residential services. The estimated overstatement is 93,110, well above the overstatement calculated using Method 1.

One other complication regarding large multifamily units is that their services may be more expensive than the typical service for single-family dwellings. The service data Mr. Paice relied on for his COS study, shows a single service for a residential customer costs somewhere between $600 to $720. Services to serve loads between 100 and 300 kW, which should be able to serve approximately from 20 to 60 residential customers, cost over $3,000. Using Mr. Paice's data on service costs and the transformer data, we adjusted the average residential service cost to $703 from $656 to account for the estimated number of customers that need larger service sizes.

Q. Would you expect that the estimates based on either of these methods will produce the same degree of accuracy?

A. No, but either estimate will be very conservative. Method 1, assuming that all multifamily units use one service for two customers does not reflect multifamily sharing for larger housing units. Method 2, adjusting services based only on numbers of larger multifamily housing, does not reflect the sharing of services by smaller multifamily housing units. There are residential customers sharing normal size and cost services in small multifamily units and also residential customers sharing more expensive services in large multifamily units. Neither method 1 nor 2 accounts for both. Note from the data cited above that the cost of larger transformers does not increase proportionally with the load that they can serve.

Q. What information does the Census provide?

A. The Census provides data by county and by state regarding housing units. In 09-035-24, OCS witness Paul Chernick used data from the 2000 Census to estimate the number of RMP customers who shared services. According to Mr. Chernick, the 2000 Census indicated that about 29% of the housing units in the counties that RMP serves were in multifamily units.

Data from the 2010 Census for the state of Utah shows that 21% of total housing units are in multifamily units, and 24% of occupied units were in multifamily units (excluding "1 unit attached dwellings".) This data also contains the number of households in different size multifamily units. It is reasonable to assume that RMP's number of customers is very close to the number of occupied housing units.

Q. Have you used the 2010 Census data to estimate residential services?

A. Yes. I applied the Census data, by County, to RMP's number of residential customers, by county. The Census data is presented for categories of housing sizes. In a previous case, Mr. Chernick was criticized for assuming that the number of units in a Census category could be represented by the midpoint – e.g. 15 units for the category 10 to 20 units.

While I do not find Mr. Chernick's representation unreasonable, in the interest of being conservative, I have utilized the bottom number of units in each category to represent the number of shared units in each category. Method 3 therefore uses the percentages of households in each category to estimate how many of RMP's residential customers will be in that category, and estimates the overstatement of services from this data. This results in finding that the lack of reflecting multifamily housing overstates the number of residential services by 129,953 services. The basis for this analysis is shown in Table 1 below.

Table 1

From Utah County ACS Data 5-yr		Estimated	
Multifamily Units	% of Customers	Number of Customers	Reduction in Services
2	3.3%	23,529	11,765
3	4.5%	32,473	21,649
5	3.7%	26,710	21,368
10	4.7%	33,514	30,163
20	3.8%	27,206	25,846
50	2.7%	19,554	19,163
Total	22.6%	162,986	129,953

Q. What do these three methods of calculating the impact of multifamily services on service plant allocation demonstrate?

A. They provide a range of estimates of how much an overstatement of the number of residential services result from the Company's assumption that every residential customer has a service. Table 2 below shows RMPs assumed number of residential services and the numbers produced by these three methods.

Table 2

Comparison of alternative calculations of the effect of multifamily housing on the number of residential services

Method	Description	Assumed Customers in Multi-Family Housing	Assumed Number of Services	Overstatement of Number of Services
	RMP Assumption	-	719,940	-
1	Duplex	158,779	640,550	79,390
2	20 Cust./Tfmr = Multifamily + Service Cost Adj.	96,424	626,830	93,110
3	Census Data	162,986	589,987	129,953

Q. What impact does this have on the amount of service plant allocated to the residential class?

A. The service plant allocator directly applies to $227.5 million of plant. It also impacts the allocation of other costs through its impact on indirect allocators. Table 3 below shows the impact of the alternative allocation based on the census data on both the amount of service plant allocated to the residential class and the resulting total revenue requirement.

Table 3[3]

	Original Service Plant	Revised Service Plant	Difference	Original Revenue Requirement	Revised Revenue Requirement	Difference
Utah	227,473,706	227,473,706	0	1,792,446,188	1,792,446,188	0
Residential Sch 1	182,945,156	175,383,119	-7,562,037	697,722,256	697,030,369	-691,887
General Large Dist. Sch 6	16,678,078	19,510,424	2,832,346	481,944,558	482,202,515	257,957
General > 1 MW Sch. 8	1,670,108	1,953,733	283,625	146,620,823	146,646,591	25,768
Street & Area Sch. 7,11,12	0	0	0	11,511,720	11,511,629	-91
General Transmission Sch 9	0	0	0	249,737,890	249,739,023	1,133
Irrigation Sch 10	0	0	0	14,597,863	14,597,905	42
Traffic Signals Sch 15TS	688,786	805,759	116,973	607,973	618,693	10,719
Outdoor Lighting Sch 15OL	149,821	175,264	25,443	954,335	956,643	2,307
General Small Dist. Sch 23	25,341,757	29,645,407	4,303,650	130,416,614	130,810,094	393,480
Industrial Contract 1	0	0	0	28,068,264	28,068,609	345
Industrial Contract 2	0	0	0	30,263,893	30,264,119	226

Q. Have you reviewed the Company's previous objections to the attempts by Mr. Chernick and by Dr. Abdulle to estimate the correct number of services serving the residential class?

A. Yes. Over the last two cases the Company has presented a litany of objections to any proposed correction to service plant allocation. I will attempt to list the most relevant of them.

1) 2000 Census data did not reflect the Company's residential customer base
2) Some multifamily dwellings have more than one service drop
3) Services serving large multifamily dwellings will be more expensive than those reflected in the residential service weight

[3] This calculation is based on the Division revenue requirement discussed later in this testimony

4) The exact number of customers in Census categories of multifamily housing are not known
5) Some other classes may also share services

Q. What do you recommend regarding the allocation of service plant?

A. I do not think it is appropriate to continue to overallocate service plant to residential customers because of imperfect data. I have produced alternative service plant allocations to “bound” the misstatement of the service plant allocator, but I recommend utilizing Method 3, as it depends on more detailed data. I believe this method still overstates the allocation of service plant to the residential class, due to the use of the minimum number of housing units in each Census category. The potential for some uncounted sharing of services in other classes may offset some of this remaining overallocation.

Q. Please discuss the allocation of substations and primary lines.

A. Substations and primary lines are allocated on twelve “distribution coincident” peaks (CPs of all distribution customers). The monthly weights are based on the percent of substations that peak in the month. The Company has not presented any theoretical support in this case for the weighting of monthly CPs in this manner, but this method has been approved in past cases.

I believe the reason for weighting the distribution CPs is to reflect the fact that substations are sized to meet relatively local peaks, and these peaks are not all coincident with the system peak. As a result, a single CP alone is not the only cost driver for distribution substations.

I am concerned that weighting by the number of substations that peak in a month does not necessarily reflect the cost of substations built to meet peaks in different months. The number of substations does not reflect the peak load on them in many months. If 10% of substations peaked in December and another 10% peaked in June, but the load of those substations which peaked in December was twice as large as those which peaked in June, it is most likely that the December peaking substations represented more investment than the June peaking substations.

Q. Are you recommending a change to the method of allocating substations and primary lines?

A. I am not. Theoretically, it would be more accurate if monthly peak loads were weighted by the cost of substations peaking in the month. However, it does not appear that this would result in a very significant change to the allocator, and the more accurate weighting by the value of substations would be very data intensive.

Q. Does the designation of distribution lines as primary or secondary have much impact on cost allocation?

A. Yes, it has a large impact. Primary plant serves all customers (except possibly for some large sub-transmission level customers). It must be sized to meet the maximum coincident load on it and is therefore allocated to all customers. Secondary plant serves only customers who take service at secondary voltage level. Almost all residential and some small general service customers take service at secondary voltage. Larger general service customers almost always take service at primary voltage, and therefore should not be allocated any secondary plant.

The more plant that is classified as secondary, the more costs are allocated to secondary service customers, who according to RMP include only residential customers and small general service customers on Schedule 23. RMP also assigns an amount of secondary plant in account 364 and 365 to Streetlighting Schedules 7, 11, and 12.

Q. Has RMP allocated secondary plant to all secondary rate classes?

A. No. It allocates secondary plant only to Schedules 1 and 23, although some Schedule 6 customers may use secondary poles and conductors. For instance, in a strip mall, when transformers reduce power to the secondary level, either there will be services directly to the secondary meter or there may be secondary lines that bring power to several meters. Many Schedule 6 customers utilize secondary meters, but I have not been able to determine how many of those may use secondary delivery service plant. Reflecting some use of secondary plant by Schedule 6 in the cost allocation would result in allocating more costs to Schedule 6 and less to Schedules 1 and 23.

Q. How does Rocky Mountain Power determine how much of their distribution lines are primary and how much are secondary?

A. Evidently this information does not come from their plant accounting data. According to the response to OCS 3.14, "Distribution split percentage for accounts 365-367 are based on data extracted from Company… records …and represent …. value of materials issued from Company warehouses for the state of Utah during a five-year period." The primary plant percentage ranges from 61% to 69% for these accounts. These data are <u>not</u> the net book value of plant in the conductor account, which would reflect the dollar amount of all conductor plant in use in Utah. However, I find these results are reasonable based on what I would expect based on standard system configuration and numbers I have seen from other utilities.

Q. Are you recommending any change at this time to RMP's primary/secondary split of plant?

A. I am not. As I indicated the primary percentage used by the Company in this case is in line with percentages I have seen from utilities with better booked data. In addition, there does not seem to be more accurate data available. I do recommend that the Company analyze the total split of its plant in future cases.

Q. Please discuss the allocation of distribution line transformers.

A. RMP uses annual class non-coincident peaks (NCPs) to allocate line transformer costs, but weights the NCPs of the classes by a "coincidence factor," that reflects the number of customers per transformer. This is relevant because for the classes with larger customers, most customers have individual transformers. For a class such as Schedule 9, transformers are really sized to meet individual customer peak loads, not the class non-coincident peak load. The Company's weighting of the NCPs seems designed to address this.

Q. Please describe RMP's allocation of general plant and administrative and general ("A&G") expenses.

A. These costs are allocated on the basis of internal allocators.

- General plant is allocated on an internal allocator reflecting all directly allocated plant
- Pensions and benefits are allocated on the basis of labor, according to Company testimony
- Accounts identified as supporting customer systems are allocated on customer factors
- All other A&G expenses are allocated based on the plant allocator

Q. Do you think all of these allocations are appropriate?

A. Not entirely. Some A&G accounts are fairly directly related to labor expense, and should be allocated on labor. These include Account 920, A&G salaries; Account 921, Office Supplies and Expenses; and Account 922, Administrative Expenses Transferred. These expenses for the most part support personnel, so I would expect them to be more closely related to labor than to plant. I have reallocated Accounts 920, 921, and 922 on a labor allocator. The Company has provided a "Labor" allocator which it uses to allocate miscellaneous labor expenses among functions. Functional costs are then allocated to the different classes using expense allocators for each function that do not include fuel, purchased power, or wheeling expense.

Q. Has the Company argued that it is not appropriate to allocate these A&G accounts on labor?

A. No, it has not. In response to discovery it indicates that a previous attempt to allocate all A&G expenses on labor was rejected. This is not an adequate rationale as to why not to use different allocators for different A&G accounts.

Q. Do you recommend changing the allocation of some A&G accounts?

A. Yes. I believe it is much more accurate to allocate the labor related A&G accounts on labor, although this will not have a big impact on the bottom line.

E. Results of Revised Revenue Requirements and Allocations

Q. Have you analyzed the impact of the various adjustments to the cost of service recommended by the Division using the model distributed by the Commission?

A. Yes. The total impact of these adjustments is shown in the following table.

Table 4

SUMMARY OF RESULTS	Utah Jurisdiction per Company	Utah Jurisdiction per Division
Total Revenues	2,083,525,276	2,055,179,988
Operation & Maintenance Expense	1,332,633,482	1,274,882,388
Depreciation	237,119,812	236,090,587
Amort of Limited-Term Plant	23,034,735	22,804,518
Taxes Other Than Income	61,276,875	57,826,466
Income Taxes - Federal	(12,715,742)	(521,056)
Income Taxes - State	1,968,968	3,626,023
Income Taxes Deferred - Net	94,260,457	94,302,956
Investment Tax Credit Adjustment	(1,545,328)	(1,545,328)
Misc. Expenses less Revenues	(648,382)	(648,382)
Total Expenses	1,735,384,877	1,686,818,172
RATEMAKING INCOME	348,140,399	368,361,816
Total Additions	10,465,276,762	10,409,568,521
Total Deductions	4,712,408,091	4,702,055,613
RATE BASE	5,752,868,671	5,707,512,908
Earned Rate of Return on Rate Base	**6.052%**	**6.454%**
Earned Rate of Return on Common Equity	6.641%	7.459%
Total Revenue Change	**172,267,339**	**88,399,042**
Existing Revenues	**1,704,047,146**	**1,704,047,146**
Total Revenue Requirement	**1,876,314,485**	**1,792,446,188**

Q. Please summarize the changes that you have recommended and made to the cost allocation study.

A. These changes are listed below:

- Wind generation capacity costs are allocated 94% on energy, 6% on demand
- The allocation of service plant to residential customers is reduced
- The allocation of A&G accounts 921, 922, and 923 are allocated on labor

Q. What are the results of these various modifications to both the Company's revenue requirement and to the allocation of costs?

A. These modifications as a whole result in increasing all class rates of return and in narrowing slightly the rate of return index. Table 5 below summarizes the changes to rates of return. Table 6 shows the impact on class calculated deficiencies, based on the Division's revenue requirement recommendations

Table 5.

	Division ROR	Revised Wind Allocation ROR	Revised Service Allocation ROR	Revised A&G Allocation ROR	All Revisions ROR
Utah	6.45%	6.45%	6.45%	6.45%	6.45%
Residential Sch 1	5.95%	6.06%	5.98%	5.89%	6.02%
General Large Dist. Sch 6	7.56%	7.59%	7.54%	7.59%	7.61%
General > 1 MW Sch. 8	6.89%	6.79%	6.89%	6.93%	6.83%
Street & Area Sch. 7,11,12	10.34%	9.84%	10.34%	9.92%	9.44%
General Transmission Sch 9	5.22%	5.03%	5.22%	5.30%	5.11%
Irrigation Sch 10	5.16%	5.06%	5.16%	5.20%	5.10%
Traffic Signals Sch 15TS	6.61%	6.46%	6.05%	6.26%	5.58%
Outdoor Lighting Sch 15OL	16.92%	15.31%	16.75%	16.92%	15.18%
General Small Dist. Sch 23	7.88%	7.95%	7.78%	7.86%	7.84%
Industrial Contract 1	3.41%	3.21%	3.41%	3.49%	3.29%
Industrial Contract 2	3.69%	3.02%	3.69%	3.77%	3.10%

Table 6

	Division Deficiency	Revised Wind Allocation Deficiency	Revised Service Allocation Deficiency	Revised A&G Allocation Deficiency	All Revisions Deficiency
Utah	88,399,042	88,399,042	88,399,042	88,399,042	88,399,042
Residential Sch 1	47,741,357	44,767,981	47,049,470	49,054,499	45,425,264
General Large Dist. Sch 6	6,861,766	6,351,699	7,119,723	6,277,403	6,032,943
General > 1 MW Sch. 8	5,062,209	5,577,172	5,087,977	4,868,738	5,402,669
Street & Area Sch. 7,11,12	-618,943	-504,124	-619,034	-508,503	-395,163
General Transmission Sch 9	20,416,716	22,303,276	20,417,849	19,834,168	21,696,503
Irrigation Sch 10	1,423,340	1,487,451	1,423,382	1,403,728	1,467,026
Traffic Signals Sch 15TS	23,079	25,960	33,799	28,982	42,621
Outdoor Lighting Sch 15OL	-190,291	-169,279	-187,983	-190,353	-167,294
General Small Dist. Sch 23	518,706	212,518	912,186	594,064	687,993
Industrial Contract 1	3,843,429	4,129,034	3,843,774	3,777,654	4,059,811
Industrial Contract 2	3,317,675	4,217,352	3,317,901	3,258,663	4,146,668

F. Revised Treatment of Working Capital, Interest, and Income Tax – Model X

Q. Please explain how Model X differs from both the original Company model and the Commission distributed model.

A. The easiest way to explain the change is to look only at the treatment of state income tax. The amount of state income tax that PacifiCorp will pay will depend on the equity portion of its earnings. The various cost of service studies should calculate the deficiency or surplus of each class assuming that they each paid the same return on equity. The Company's total return on equity is allocated to classes based on their relative rate bases. The original Company model and the Commission distributed model that attempts to replicate the Company model calculate state income tax[4] based on the Utah allocated return on equity. Then it allocates this total amount across classes based on income before tax ("IBT"). If a class earns less than the average return, its allocated state income tax will be less than if it earned the average return.

The model further does a number of calculations based not on the returns earned by each class but on the dollars necessary to move from the average Utah earned return to the system requested return. These calculations ignore the basic fact that various rate classes in the forecast test year earn more or less than the average return.

Q. What does Model X calculate that the original Company model does not?

A. Model X calculates the total costs that would be attributable to each class if each class paid the system rate of return.

Q. Have you used Model X to calculate class cost of service and revenue deficiencies based on the Division revenue requirement?

A. Yes. I also made in this model the same changes to cost allocation that I recommend and calculated in the model distributed by the Commission. Model X tends to slightly increase the calculated deficiency of classes that earn less than the average rate of return, and vice versa. Table 7 below shows the class deficiencies in dollars and in percentages based on my version of the Commission distributed model and also on my version of Model X.

[4] Based on an average of state income taxes paid by PacifiCorp.

Table 7.

	Original Model Deficiency	Model X Deficiency	Original Model % Increase	Model X % Increase
Utah	88,399,042	88,449,574	5.19%	5.19%
Residential Sch 1	45,425,264	50,547,518	6.99%	7.78%
General Large Dist. Sch 6	6,032,943	-4,796,981	1.27%	-1.01%
General > 1 MW Sch. 8	5,402,669	4,427,928	3.82%	3.13%
Street & Area Sch. 7,11,12	-395,163	-523,098	-3.26%	-4.31%
General Transmission Sch 9	21,696,503	27,991,650	9.46%	12.21%
Irrigation Sch 10	1,467,026	1,868,052	11.14%	14.18%
Traffic Signals Sch 15TS	42,621	49,860	7.29%	8.52%
Outdoor Lighting Sch 15OL	-167,294	-286,665	-14.62%	-25.04%
General Small Dist. Sch 23	687,993	-2,394,142	0.53%	-1.84%
Industrial Contract 1	4,059,811	5,649,841	16.76%	23.32%
Industrial Contract 2	4,146,668	5,915,612	15.39%	21.95%

III. LOAD RESEARCH AND ESTIMATION OF PEAK LOADS

Q. Why is load research data important in the cost allocation study?

A. The load research data is essential for estimating peak load allocators for classes that do not have hourly metered data. Furthermore, the load research data yields valuable information about class load shapes and how much energy customers in different classes use during high-cost and low-cost time periods.

Q. Has RMP's load research data been an issue in prior cases, and what was the result?

A. Yes. In the 2009 GRC, RMP's load research was of such concern that two Workgroups were established to examine the topic. The Workgroups found three significant issues in the load research data used for prior cases:

1. An out-of-date sample
2. An out-of-date sample design
3. A lack of weather normalization of the data

Of these three issues, the first issue was partially fixed in the current case by the inclusion of load research data from new sample meters that were installed in 2008 for Schedule 6 and Schedule 23. The out-of-date sample design, which fails to accurately capture within-class variability in load-shapes, remains an issue. The Workgroup recommended the Company accelerate its planned 2017 load research sample replacement to 2014. Furthermore, the Workgroup recommended that the load research data be weather normalized before being used to calculate load allocators.

The load research data utilized in this case reflects neither updated sample design nor weather normalization of the data.

Q. What were the findings of the Workgroups on load research and peak-hour forecasting?

A. The Workgroups found that there were significant differences between the peak hours calculated from the load research data and the peak hours calculated from the jurisdictional load forecasts. Most parties believed that calibration was a useful interim approach for mitigating these differences, but more importantly, some kind of weather normalization is needed to ensure proper peak hour forecasts. The Workgroups did not reach an agreement as to how to implement the weather normalization, but there was a general consensus that some sort of weather normalization was needed.

Q. How has the Company projected peak loads, and what is the relationship between these projections and the load research data?

A. The Company has forecasted the timing and amount of monthly Utah total peak loads using its jurisdictional forecast methodology, which also forecasts the day and hour of each month's peak. Ideally, the sum of class peak loads that are projected from the load research data should equal the jurisdictional forecast of total load. When projections calculated from the load research data did not closely match the forecast peaks, the Company "calibrated" the results to bring monthly peak estimates resulting from load research closer to the peaks that it projected in its jurisdictional forecasts. RMP then adjusted the peak data resulting from the load research to bring it closer to the peak estimates derived from its Utah class forecast.

Q. Does it appear that either the energy or the peak loads of the Irrigation class have been projected accurately?

A. No. The load of the irrigation class is related to rainfall as well as to temperature and is clearly difficult to forecast. The Company acknowledges the relationship to rainfall in the response to DPU 24.17, when it states that the large deviation is due to a wet spring. This type of load is difficult to predict, as it is related to the size as well as the number of customers, agrarian economics, rainfall, temperature, and probably other factors. The sample which the Company relies on was drawn from customers who were irrigating in

2003, 2004, and 2005. All of these factors suggest that both the irrigation energy forecast and peak load estimates will not be very reliable.

Q. How do you recommend responding to the apparent lack of accurate data on the irrigation class?

A. The lack of accurate data is a major issue regarding this class. We cannot determine if normal weather loads have been under or over projected for this class. In addition, it may not be appropriate to address the non-coincident peak loads of these customers in the same manner that other class loads are treated.

The cost of service study estimates that this class has relatively large deficiency, more than double the average deficiency. However, this increase can be limited by a cap on all rate increases. I recommend that this class should not receive a very large increase until the underlying load data has been improved. I also recommend that the Company propose rate design changes for this class aimed at improving the load shape of the class by shifting more load to off peak hours.

IV. DISCUSSION OF COMPANY'S MARGINAL COST STUDY

Q. Mr. Paice prepared a marginal cost study to comply with the Commission's Order on Rate Design in 09-035-23. Please comment on this marginal cost study.

A. I find that this study has numerous shortcomings. There are major conceptual flaws which make me doubt its validity for ratemaking purposes. The normal approach to relying on marginal cost analysis for guidance in developing rates is that an energy charge should inform customers of how much additional cost is incurred in the short run when customers use additional energy, and a capacity charge should inform customers of how much it will cost to add capacity if peak load increases.

Q. Could you describe some of the aspects of the Company's marginal cost study that are problematic?

A. Yes. The depiction of the marginal cost of generation seems to overstate the marginal generation cost. The initial calculation of the marginal cost of capacity is based on the cost of a simple combustion turbine, which should be the least expensive way to meet peak load. The marginal cost of energy, however, increases the variable cost of energy by adding to it a capitalized energy number. This reflects the difference between a combined cycle unit and a combustion turbine. This capitalized energy cost is not normally included in a short-run marginal cost calculation. I also find problems with some of the methods of estimating different components of marginal distribution costs. It is my expectation that the Company has overstated marginal costs. If short-run marginal energy costs are added to all of the fixed components of marginal cost, the total marginal cost would be $0.1103/kwh.

V. RATE DESIGN PRINCIPLES

Q. Have you found any problems with the Company's proposed rate design?

A. Yes. Fundamentally, the Company does not seem to have attempted to design rates to send better price signals or to improve the efficiency of use. Its major approach to rate design appears to be to produce even bill impacts across different customers within rate classes. While bill impacts should be considered, when the basic rate design has not been examined or justified in many years, the Company's approach may actually be moving rates further from appropriate price signals.

A. Residential Customer Charge

Q. What has the Company proposed regarding the residential customer charge?

A. The Company has proposed to increase the residential customer charge from the current \$4.00 per month to \$10.00 month, an increase of 150%. I believe this change is neither consistent with cost allocation or gradualism principles.

Q. How does the Company justify such a large increase?

A. Mr. Griffith testifies that the current residential customer charge fails to recover what he defines as the "fixed costs" of serving residential customers, and that it is the lowest residential customer charge in the Company's system. He discusses three alternative definitions of customer costs, which all support customer charges higher than the current residential charge. All of these definitions include more costs than the currently approved Commission methodology, which includes only the return on and depreciation expense associated with meters and service drop plant, and the expense of reading meters (Account 902.1) and billing expense (Account 903.2).

Q. Please describe the three alternative methods of calculating customer costs.

A. Mr. Griffith presents the method producing the highest customer cost first. Method 1 includes what he calls "fixed costs" of the distribution function, the retail function, and the miscellaneous function. This results in a computed residential monthly customer cost of $28.63. Method 2 is called the Commission's 1985 Methodology. It includes the return on and depreciation expense associated with meters and service drop plant, and certain customer-related expenses - the expense of reading meters (Account 902.1) and billing expense (Account 903.2). This results in an average customer cost of $3.85 per month. Method 3 is called the "2012 Methodology". It adds to the 1985 Methodology the maintenance expense associated with meters and service drops, allocated "retail costs", basically all of Accounts 901 and 919, and a portion of costs associated with transformers, which the Company claims are customer related. This method produces a residential customer cost of $11.60.

Q. Do you think that Method 1 is supportable?

A. No. The Company is clearly trying to recover more of what it labels "fixed costs" through a customer charge. This is a rather artificial concept. Essentially all utility plant is fixed in the short run. Generation plant, for example, is certainly fixed in the short run. However, that does not mean that it is appropriate to collect the cost of this plant through a customer charge. Since all plant is variable in the long-run, collecting these plant costs through a customer charge may send the wrong price signal, and could lead to misallocating this plant. With regard to what the Company labels "retail costs", while it might be argued that some of these costs are considered directly customer related, the Company has not provided any evidence that these should all be included in customer costs.

Q. Do you think it is appropriate to include all "Retail Costs" in the calculation of customer costs?

A. No, I do not. The cost causation principle suggests that costs should be considered as customer costs only when the major cost driver of the costs is in fact the number of customers – i.e. as customers are added, the costs increase. The customer accounting and billing (Account 903.2,and customer metering (Account 902.1) costs that have been included in the 1985 Methodology are fairly directly related to the number of customers. Even with regard to these costs, I say "fairly" directly related, because there are enough economies of scale in the customer accounting function that a large number of customers could be added without increasing costs.

The "All Other Retail Function" cost item, other FERC 900 accounts, that the Company proposes to add to customer costs, appears to contain a number of accounts which are not primarily caused by the number of customers. Demand-side Management costs, which I believe are primarily reflected in Account 908, are driven by programs that are intended to reduce peak load and increase the efficiency of use of electricity. This is related not to the number of customers but to programs to make usage more efficient and to reduce costs, particularly generation costs. Account 904, uncollectibles, is driven not by the numbers of customers but by revenue levels and by customers' ability to pay.

Q. Is there evidence that other 900 accounts and subaccounts that are driven by the number of customers?

A. No. In fact the titles of a number of 900 subaccounts, and detailed cost categories within subaccounts, suggest that the underlying costs are not customer related. For instance, Account 910.0 is an "outside facilitator for joint planning effort with cities and counties to set facility siting criteria." There is a "customer guarantee program" in Account 905.0. Account 909, Information/Instruction, includes customer and communications group; it is possible that the amount spent on larger customers is greater than that spent on residential customers. Detailed data on Account 903 does not support including all of these costs as customer-related (this account includes 903.2 which is included already in customer costs). Detail on the 903 account is shown below in Table 8.

Table 8

Total Company Subaccount Detail for Account 903*
July 1, 2010 - June 30, 2011

FERC Subaccount	Description	Amount	Utah	Percentage of Total
903.0	CUST RCRD/COLL EXP	$880,302	$450,086	1.6%
903.1	CUST RCRD/CUST SYS	$4,036,506	$2,063,811	7.1%
903.2	CUST ACCTG/BILL	$12,024,229	$6,147,826	21.3%
903.3	CUST ACCTG/COLL	$18,414,578	$9,415,126	32.6%
903.5	CUST ACCTG/REQ	$164,543	$84,129	0.29%
903.6	CUST ACCTG/COMMON	$20,992,557	$10,733,212	37.1%
Total 903		$56,512,714	$28,894,190	100%

The largest subaccount is 903.6, which seems to be a fairly general catchall that is not clearly customer related. For instance, detailed data provided in response to OCS-15-3 shows there are many costs labeled “Business Integration”. It is not at all evident why this would be customer related. It also contains various renewable education (Wind Farm tours), DSM and energy efficiency related expenses, and even a category labeled “Establish relationships with Commission.” The next largest subaccount in Account 903 is in 903.3. Data provided in response to OCS 15-5 indicates that much of this is related to local collection offices and training. It seems that this would be more related to geography rather than to numbers of customers.

The Division and the Office, through the discovery process, have attempted to ascertain why any of these costs should be considered customer related. The Company has provided numbers, but has not attempted to provide appropriate explanation of subaccounts that would justify them being treated as customer related. In response to the question “Please explain the purpose of each of the following expenditures and why RMP believes it is appropriate to recover them through the customer charge,” referring to a number of subaccounts, it provides no explanation but simply refers to Mr. Griffith’s testimony, which simply says retail costs are fixed, and should be included in the customer charge.

Q. What do you recommend regarding the treatment of "Retail Costs"?

A. It is not clear that any of the 900 accounts except for 902.1 and 903.2 should be included in customer costs. I recommend that the Commission not include any of the additional 900 accounts in the customer charge unless the Company fulfills its obligation to provide a full explanation as to how they are customer related and why the number of customers in a class should be the basis for their allocation.

Q. Does Method 2 include all customer-related costs?

A. Method 2, the existing approved methodology, does not include all costs associated with meters and service drops. If these plant items are clearly and directly related to the numbers of customers, all costs associated with them are also customer related. It is inconsistent to allow the costs associated with financing the plant items, but not the maintenance costs necessary to keep these items operating.

Q. Method 3 adds to Method 2 the costs you discussed above, but also adds a portion of costs associated with transformers. What is the basis on which the Company claims that a portion of transformer costs are customer costs?

A. Mr. Griffith argues that as transformer costs increase at a lower rate than the capacity they can serve, a portion of transformer costs are fixed costs necessary to serve customers.

Q. Do you think that the Company's estimate of a customer-related transformer cost is meaningful for cost allocation?

A. No. In response to OCS-3.38, the Company provided a study that is supposed to estimate the customer-related portion of transformers. This is basically a regression analysis of 2009 transformer installations. This equation estimates the cost of a transformer as a function of the KVA size of the transformer. It produces a coefficient and an intercept. The Company interprets the intercept from this equation as "commitment related" cost, which it evidently considers a customer cost. This equation simply tells us that based on 2009 investments, as transformer sizes increase, the cost of the transformer increases at a slower rate. Nor does it tell us that a major driver of transformer cost is the number of customers.

While this relationship may be important for engineering and design, it is not a measure of the marginal customer cost. An estimate of the marginal demand cost would tell us how much would be spent on transformers for a given increase in peak load. This analysis simply shows that the cost of the transformer does not increase linearly with the size of the transformer, but that cost increases at a slower rate. The intercept of this equation is not a marginal customer cost.

Conceptually, customers can be added in many locations without investing in additional transformers, but additional load is a catalyst for transformer investment. Transformers are only necessary because of the size of system loads. For very small loads, power would be delivered on secondary lines, as line loss would not be an issue. The method of estimating the customer related portion of transformers has a number of problems. The analysis of the relationship between demand and cost uses all types and sizes of transformers rather than only the transformers used for residential customers. It is also based on only the plant that the Company is currently installing and on the typical size customers; if customers were smaller, more of them could share transformers and the results would be different.

Q. Does this analysis of economies of scale in transformers provide an appropriate basis to include transformer costs in a customer charge?

A. No, it is not. While the Company might like to collect virtually all of its plant costs through monthly fixed charges, this approach results in charging too much to small customers within each rate class (since smaller customers usually require less plant than average customers in a class) and also may result in not providing appropriate price signals. The more costs that are collected through a fixed monthly charge, the less that rates will communicate that as load increases, costs increase; both generation and delivery costs will increase as the Company will have to add more plant.

Q. Do you believe any changes to the 1985 Methodology are justified?

A. Yes. I believe that it is appropriate to add in to the current definition all costs associated with services and meters. I will call this the Division 2012 Methodology. All of these various methods are illustrated below in Table 9.

Table 9.

Comparison of Residential Customer Charge Calculation Methodologies

Description	1 Fixed Costs Methodology	2 1985 Methodology	3 2012 Methodology	4 Division 2012 Methodology
Customer Billing & Accounting Expense (acct. 903.2)	$0.62	$0.62	$0.62	$0.62
Meter Reading (acct. 902.1)	$0.52	$0.52	$0.52	$0.52
All Other Retail Function	$3.52		$3.52	
Meters - Depreciation Expense	$0.21	$0.21	$0.21	$0.21
Meter Expense (acct. 586)	$0.17		$0.17	$0.17
Meter Maintenance (acct. 597)	$0.23		$0.23	$0.23
Meter Plant (acct. 370)	$0.70	$0.70	$0.70	$0.70
Meters - Accumulated Depreciation	-$0.25	-$0.25	-$0.25	-$0.25
Service Drop - Depreciation Expense	$0.40	$0.40	$0.40	$0.40
Service Drop Plant (acct. 369)	$2.25	$2.25	$2.25	$2.25
Service Drop - Accumulated Depreciation	-$0.61	-$0.61	-$0.61	-$0.61
Transformers - Customer Related	$3.28		$3.28	
All Other Distribution - Service Drop	$0.53		$0.53	$0.53
All Other Distribution -Transformer	$0.65			
All Other Distribution - Poles and Conductors	$11.94			
All Other Distribution - Substation	$4.10			
Miscellaneous Function	$0.36			
All Other Distribution - Meters				$0.18
Total Customer Charge	**$28.63**	**$3.85**	**$11.60**	**$4.97**

Q. Based on the Division 2012 Methodology, what would you recommend for a cost-based customer charge, and what bill impacts will this charge have?

A. The computation of a residential customer cost based on the Company's original filing is $4.97. The cost based on the Division's recommended rate of return will be minimally less. In the interest of rate simplicity, I would set the residential customer charge at $5.00. This rate design change by itself will tend to create larger percentage decreases to very small residential customers compared to larger residential customers. This impact on bills should be considered in designing other rate components.

B. Company's approach to remaining components of Rate Design

Q. What appears to have been the Company's approach to other components of rate design?

A. The Company proposes to increase uniformly customer, facility, demand and energy charges. It makes no claim that the resulting rates provide signals for efficient use or that rate changes are based on any analysis. This major characteristic of this approach is that it produces even bill impacts to different customers within rate classes.

Q. Are the Company's time of use ("TOU") rates effective tools to encourage customers to shift load from peak to off-peak hours?

A. No, they are not. The rate is also clearly not very attractive as there are very few customers on it. The bills of residential time of use customers are based on standard rates, modified by additional energy charges for on-peak use and by credits (negative rates) for off-peak use. In this case, the Company has proposed an increase to both the on-peak charge and the off-peak credit. The Company has presented no analysis of how much customers on this rate can benefit from shifting load or whether it is an effective load management tool. This rate change will not make the rate any more attractive than the existing R-2.

Commercial TOU customers on Schedule 6A have different peak and off-peak energy rates for each season. The resulting rates are on average much higher than for non-TOU customers on Schedule 6. The facilities charge per kW on Schedule 6A is much less than the power charge per kW on Schedule 6 but the time differentiated energy charges are much higher. Presumably, this was done deliberately so that most of the 6A bills are based on peak energy usage and not demand, and thus customers are encouraged to conserve during all peak hours.

C. <u>Other Rate Design Recommendations</u>

Q. You recommended that the residential customer charge be set at $5.00 for single phase residential customers. Do you have any other recommendations regarding the residential rates 1 and 2?

A. Yes. I recommend that that the summer tailblock not be increased more than the Company has proposed, as this charge is greater than marginal cost. I also recommend that energy charges be designed to partially mitigate the impact on small customers of the increase in the customer charge. I will discuss specifics in Section VI below.

Q. What do you recommend with regard to the TOU rates?

A. I recommend that there be no increase to the residential TOU rate. The increase to the customer charge then requires that some component of energy charges be reduced. Since the basic block energy charges will continue to be the same as the charges on R-1, I recommend that this be effectuated primarily through an increase in the credit and increase in the discount for use during off-peak hours.

Q. What do you recommend for other major rates?

A. I recommend that other rates be adjusted through equal percentage changes to all rate components. I do not believe that this will create the most effective price signals, but I do think this a reasonable alternative until the Company provides an updated analysis regarding how its demand and energy costs should be communicated to commercial and industrial ("C&I") customers. In addition, it should review whether the present definitions of C&I classes are appropriate, and determine potential bill impacts resulting from modifying its C&I rates.

VI. RATE SPREAD AND RECOMMENDED RATE DESIGNS

Q. How has the Company proposed to spread its revenue requirement across rate classes?

A. The Company proposes a rate spread midpoint of 10.5%. Class increases are set at discrete differences from this midpoint, rather than directly referencing class cost of services. Increases to Schedule 9 and 10 are considerably mitigated compared to the cost of service results. The Company's resulting proposed increases are:

Schedule 6 and Schedule 23 – 8.5%

Schedule 8 – 9.5%

Residential – 10.5%

Schedule 9 – 12.5%

Schedule 10 - Irrigation – 13.5%

Q. Are you recommending an alternative rate spread based on your analysis of the Division's recommended revenue requirement, and your modifications to the cost of service study?

A. Yes. The Division is recommending a revenue requirement that would result in an average increase to all classes of 5.19%.

The range of percentage deficiencies to major rate classes, based on Model X, the Division's recommended revenue requirement and the allocation changes that I have made, is roughly from -1% to +14%, although the largest deficiency is for the irrigation class, which results partly from questionable load data. These numbers suggest that while classes can be moved toward equal rates of return, there is also a need for mitigation of some increases. Table 10 below shows class deficiencies, rates of return, and the rate of return index based on the Division's cost of service using Model X.

Table 10

RORs & Deficiency Based on Division Revenue Requirement

Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	Residential	649,980,899	6.04%	0.94	700,528,417	50,547,518	7.78%
6	General Service - Large	475,082,792	7.64%	1.18	470,285,811	(4,796,981)	-1.01%
8	General Service - Over 1 MW	141,558,614	6.83%	1.06	145,986,542	4,427,928	3.13%
7,11,12	Street & Area Lighting	12,130,663	8.67%	1.34	11,607,565	(523,098)	-4.31%
9	General Service-High Voltage	229,321,174	5.06%	0.78	257,312,824	27,991,650	12.21%
10	Irrigation	13,174,523	5.08%	0.79	15,042,575	1,868,052	14.18%
15	Traffic Signals	584,894	5.63%	0.87	634,754	49,860	8.52%
15	Outdoor Lighting	1,144,626	15.30%	2.37	857,961	(286,665)	-25.04%
23	General Service - Small	129,897,908	7.81%	1.21	127,503,766	(2,394,142)	-1.84%
SpC	Customer 1	24,224,835	3.25%	0.50	29,874,676	5,649,841	23.32%
SpC	Customer 2	26,946,218	2.98%	0.46	32,861,829	5,915,612	21.95%
	Total Utah Jurisdiction	1,704,047,146	6.45%	1.00	1,792,496,720	88,449,574	5.19%

Q. What do you recommend in terms of rate spread?

A. I recommend that rate increases should be capped. I recommend a minimum increase of 1.5% to each class other than the streetlighting classes, for whom I recommend no revenue change. I have set the cap on increases at 1.7 times the average increase. This results in a maximum increase that is less than 9%. The revenue that is not collected because of the rate caps is then collected through a small additional increase to the three classes whose initial increases are well below the system average increase. If the cap were lower, the maximum increase would be less but there would have to be a greater increase to the classes that are recovering the amount created by the cap. I believe these parameters result in a reasonable range of rate increases. This rate spread is shown in Table 11 below.

Table 11

Division Recommended Rate Spread

Schedule No.	Description	Annual Revenue	Increase (Decrease) to = ROR	Percentage Change from Current Revenues	Capped %age Change	Revenue Impact of Caps	Final Increase (Decrease)	Final %age Change
1	Residential	649,980,899	50,547,518	7.78%	7.78%	0	50,547,518	7.78%
6	General Service - Large	475,082,792	(4,796,981)	-1.01%	1.50%	11,923,223	9,004,745	1.90%
8	General Service - > 1 MW	141,558,614	4,427,928	3.13%	3.13%	0	4,987,658	3.52%
7,11, 12	Street & Area Lighting	12,130,663	(523,098)	-4.31%	0.00%	523,098	0	0.00%
9	Gen Service-High Voltage	229,321,174	27,991,650	12.21%	8.82%	(7,756,463)	20,235,187	8.82%
10	Irrigation	13,174,523	1,868,052	14.18%	8.82%	(705,538)	1,162,513	8.82%
15	Traffic Signals	584,894	49,860	8.52%	8.52%	0	49,860	8.52%
15	Outdoor Lighting	1,144,626	(286,665)	-25.04%	0.00%	286,665	0	0.00%
23	General Service - Small	129,897,908	(2,394,142)	-1.84%	1.50%	4,342,611	2,462,092	1.90%
SpC	Customer 1	24,224,835	5,649,841	23.32%	23.32%	(5,649,841)	0	0.00%
SpC	Customer 2	26,946,218	5,915,612	21.95%	21.95%	(5,915,612)	0	0.00%
	Total Utah Jurisdiction	1,704,047,146	88,449,574	5.19%	0.00%	(2,951,857)	88,449,574	5.19%

Q. Have you designed rates that will collect the revenues resulting from this rate spread?

A. Yes, for all of the major classes. These are attached as DPU Exhibit 8.2 DIR-COS. As noted earlier, the only significant rate design changes were to the residential rates.

Q. Please discuss your proposed residential rates.

A. First, they all have customer charges of $5 and $10 for single and three phase service customers. This increase in the customer charge was offset to some extent by a lower first block charge in the summer, and the creation of two blocks in the winter, with the first block set at the same rate as the summer first block. I left the third summer block at the Company's proposed rate, but increased the second block by one cent per kwh. This is in order to moderate the increase to the second winter block, while still collecting the revenue targets. As noted earlier, I set the TOU Rate R-2 to produce no increase from the forecasted revenues. I decreased the on-peak adder and increased to off-peak credit. In addition I have not introduced a block rate in the winter for this rate, as I do not have bill frequency data for this rate. These changes to Rate R-2 were designed to produce the revenue target as the customer charge and second and third blocks of the R-1 rate increased.

Q. Does this conclude your testimony?

A. Yes, it does.