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. 10-035-124** **DPU Exhibit 16.0 D-COS**

COST OF SERVICE

DIRECT TESTIMONY OF LEE SMITH

ON BEHALF OF

THE UTAH DIVISION OF PUBLIC UTILITIES

June 2, 2011

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 27 years. I have prepared testimony on gas and electric rates, rate adjustors, cost allocation and other issues regarding more than 40 utilities in 20 states 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 16.1D-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").

Q. Please summarize your testimony.

A. I testify on: a number of issues related to the Company's allocated cost of service study; the Company's load research and its estimation of peak loads; several rate design issues, including customer charges and time of use rates; the Company's marginal cost study; and rate spread. I have found that:

- The allocation of generation and transmission costs within Utah is not consistent with the jurisdictional allocation;
- A number of the Company's jurisdiction allocators should be modified, but the impact of these modifications is not large;
- The Company's estimates of class peak loads are not fully consistent with the recommendations of the Workgroup which reviewed this methodology after the last rate case;
- The Company's proposed increase in the residential customer charge is not warranted;
- The Company's proposed Time of Use rates are not efficient price signals and should be modified;

- The Company's marginal cost study is flawed and probably understates marginal costs; and
- An alternative rate spread is reasonable given the Division's recommended revenue requirement.

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.

<u>A. Differences Between Jurisdictional and Utah Allocations</u>

Q. Are the allocators that RMP has used in its Utah class cost of service study the same as those used in its Jurisdictional Allocation Model ("JAM")?

A. Many of the allocators are the same, but there are some differences. I place these differences into three categories:

- those that have an insignificant impact;
- those that are justified by differences between jurisdictional allocation and Utah class allocation; and
- those that are not fully justified and which may have a significant impact.

Q. Why are some allocator differences relatively insignificant in the cost allocation process?

A. Generally, this is because the costs allocated on them are quite small. In addition, the differences between the JAM and the Utah allocators may be small. In both cases modifying the Company's cost study will have an insignificant impact on the results.

Q. Are there some Utah allocators which are appropriately different from the JAM allocators, and why is this the case?

A. The short answer is yes. This is particularly true of the allocation of a number of costs which are related to customer service, 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. For instance, to allocate meter reading between jurisdictions the unweighted number of customers is appropriate if the mix of customers between the different jurisdictions is fairly similar. The allocation to Utah customer classes should reflect differences in the costs of reading different types of meters. For instance, the cost of reading the Schedule 6 demand meters is higher than the cost of reading Schedule 1 meters without demand, and in addition Schedule 6 has a much higher percentage of meters read via phone, which is more expensive. As a result the Schedule 6 average meter reading cost is about double that of Schedule 1 meter reading cost. The weighted allocator Factor 47 reflects that interclass difference. Another example is uncollectible accounts. These should be directly accounted for between Utah and the other jurisdictions. Within Utah, these are allocated between classes based on the net write-off amounts booked for each Utah class in 2010. The Schedule 1 percentage of net write-offs was about 80%, whereas the Schedule 1 number of customers allocator is about 87%.

I would not change the Company's Utah allocators for a number of accounts, even though they may seem to differ from the JAM allocation.

Q. Which allocators are likely to result in errors in the cost allocation process because they are different in the Utah and the JAM allocation?

A. The weighted demand and energy allocator is applied to a large amount of costs, including transmission expense, generation plant, and transmission plant. The allocator used in the JAM process is not the same as that used in the Utah class allocation, even though the weights on demand and energy are the same. The Utah allocator weights monthly coincident peaks, while the JAM allocator does not.

Q. What is the result of this difference?

A. Since Utah's cost responsibility for generation capacity is determined by one allocator, and the cost of that generation capacity is spread across customer classes on another basis, there is a mismatch that could be significant. The intrastate allocation is imposing more costs on classes that use a higher percentage of power during a single coincident peak, but the single coincident peak does not actually have any additional weight in the

JAM allocation that results in RMP's responsibility for generation and transmission capacity.

B. Do RMP's Intrastate Allocations Reflect Cost Causation?

Q. Do you have any comments on RMP's Intrastate Allocations, aside from any differences between them and the JAM allocations?

A. Yes. I will describe a number of allocators, including those applied to generation capacity, Net Power Costs, transmission, distribution plant, customer expenses and administrative and general expense, and recommend certain changes to the proposed allocations.

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 what it calls F10, but which I refer to as F10W, to distinguish it from the JAM allocator, which uses unweighted coincident peaks. This allocator weights the demand allocator 75% and the energy allocator 25%. The demand portion weights class monthly peaks coincident with the monthly peaks of the entire PacifiCorp system. Each month is assigned a weighting factor calculated as a ratio between the system monthly peak value to the maximum system monthly peak value for the entire year considered. Thus if the maximum system peak load for the year occurred in July, then July would receive a weighting factor of one. Each other month would have a lower weighting factor based upon the ratio between that month's peak and the July peak. As noted earlier, in Section II A, the allocation on the basis of weighted monthly peaks does not reflect how PacifiCorp actually allocates generation and transmission costs to RMP. The PacifiCorp JAM allocation, which treats each month the same, is reflected in RMP's claimed revenue requirement in this case. The weighting factors used in the intraclass allocation put more emphasis on a single coincident peak than the JAM allocation as it effectively allocates more costs to classes with higher peak demand at the time of the system maximum annual demand.

Q. How has RMP allocated Net Power Costs?

A. Net Power Costs are allocated differently depending on the type of cost. Monthly fuel costs and non-firm purchases and sales are allocated on the basis of monthly energy. The allocators for firm purchases and sales are similar to Factor 10 used to allocate fixed generation and transmission costs, but differ in two key respects: a) they do not weight monthly demands and b) a 75% demand/25% energy allocator is developed for each month for each class to apportion the monthly Utah firm purchases and sales.

Q. What do you recommend regarding the allocation of net power costs?

A. I recommend that this issue should be reviewed, primarily with regard to whether firm purchases and sales should be allocated on the same basis. Firm sales can be made because of the existence of excess generating capacity in some hours; firm purchases will reflect both past contract commitments and the system need for energy and capacity. Allocating both purchases and sales on the same basis may oversimplify the situation.

An ideal allocator might need to consider net power costs on an hourly basis, and to split purchase costs between capacity costs and energy costs. This analysis might be very data computationally intensive. I believe the issue of whether more granularity in the allocation of purchases and sales is called for should be further reviewed.

A preliminary look at the short-term sales and purchases from the Company's GRID model indicates sales may be weighted more toward high-load hours while purchases may be weighted more toward low-load hours. However, this only addresses short term sales and purchases which are relatively small.

Q. How has RMP allocated distribution costs in the Utah cost of service study?

A. As in most cost of service studies, the initial step in distribution cost allocation requires allocating distribution plant on the basis of external allocators; most distribution expenses are then allocated on the basis of the internal allocators, which are dependent upon the allocation of plant that is most closely related to the expense. Meters and Services are treated as customer related and allocated on the basis of weighted numbers of customers. Other distribution costs are treated as demand related, and classified as either primary or secondary. Substations, poles and primary lines are treated as primary and allocated on the basis of weighted monthly distribution peaks. Secondary lines and line transformers are allocated on the basis of weighted non-coincident peak ("NCP") demands.

Q. Please explain what is meant by external and internal allocators.

A. External allocators are generally characteristics of customers or of load that can be measured or estimated directly. These include such things as the numbers of customers in each class, the energy used in a period of time, and the peak loads of the classes. These allocators are applied to costs that appear to be related to and primarily caused by these characteristics; for example as fuel costs are caused by how much energy is generated and are allocated on that basis. Internal allocators are based on what seem to be appropriate combinations of the direct allocations. For instance, general plant "supports" all of the utility functions, and could be allocated on an allocator that resulted from summing up all of the direct plant allocations.

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

A. Yes, I believe there are. The weighting of the monthly peaks is problematic; and the treatment of costs as secondary or primary does not seem to be based on actual costs.

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 difference in cost of plant associated with different months. In response to DPU DR 14.8, which asked how the number of substations peaking in different months was related to cost causation, the Company referred to the testimony of Lowell Alt in Docket No. 09-035-23. This testimony discussed the fact that there is variation in when substations peak, and that the number of substations peaking could be used to weight the importance of monthly peaks. However, it also stated clearly that projected peak load is the key driver in sizing substation equipment. 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.

This suggests that it would be more accurate if weighted by cumulative size (kW) of peaking substations. There are a number of very small substations included in the count. If the CPs were weighted by the size or the cost of the various substations the allocator would better reflect cost causation.

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. Do you agree with how RMP has allocated secondary plant to only certain rate classes?

A. No, I do not. I expect that customer-owned Traffic Lights (12 TS) and Outdoor Lighting (12 OL) also use secondary plant. Also, there should be some allocation of secondary plant to Schedule 6. The response to DPU DR 21.15 states that there are some Schedule 6 customers who take service at secondary. Moreover, the sample data which the Company used to calculate line losses found about 3% of Schedule 6 load was at secondary voltage, according to DPU DR 6.15. This should be recognized in the allocation of secondary plant, some amount of which should be allocated to Schedule 6. If a total of 5% of the Schedule 6 load was actually served at secondary, and this was reflected in the cost allocation, this would have a significant impact on the cost allocation, with more costs allocated to Schedule 6 and less to Schedules 1 and 23.

Q. How have you reflected this in your modifications to the allocated cost of service study?

A. I developed a new allocator, F22A, which reflected 5% of the NCP of Schedule 6 and the NCPs of the Schedules 12 TS and 12 OL, which I applied to Account 365. This new separate allocator was used so as not to change the allocation of underground plant, which utilized Allocator F22.

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 DPU DR 21.4, the "secondary/primary distribution split percentage for account 365 is based on data extracted from Company records and represents the five-year average value of materials issued from Company warehouses for the state of Utah." The response to DPU DR 21.4 states that "the five-year average dollar value of materials issued from Company warehouses indicates that approximately 57% of overhead conductor was secondary related." During this period evidently more than half of the length of overhead conductor installed was secondary. This data is <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.

Q. Do you think this may be reasonable proxy for the value of conductor plant?

A. I do not. I would expect to see more than 50% of total conductor being primary, and secondary somewhat less than 50%. The reasons are both the length of primary and secondary conductor wire and the relative cost of primary versus secondary conductor. The distribution wires system usually consists of poles which carry both primary and secondary conductor. The length of the primary and secondary wires will be the same along these sections. There usually are also some poles which carry only primary conductor. This leads to the expectation that there will be more miles of primary than of secondary conductor. DPU DR 21.5 asked for "the configuration of distribution system installations that result in more dollars of secondary than of primary conductor, and indicate the reasons for such installation." The Company's response stated that "The five-year average percentage of dollars is not meant to represent any specific configuration for the Utah distribution system." It provided no further explanation as to how there might be more secondary than primary conductor on the system. In addition, the normal primary conductor will usually cost more per foot than the normal secondary conductor, comparing overhead to overhead and underground to underground.

In the last case, the Company reported that the percentage of the value of secondary to total conductor plant was only about 14%. While this percentage is lower than I would expect, it further casts doubt on the 57% split that is being used in this case.

Q. How do you recommend treating the primary/secondary split?

A. I modified the ratio between primary and secondary plant in Account 365 to a 50/50 split. As expected, this reduced the deficiency of the classes that take service at secondary and increased the deficiency of other classes.

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 what they call a "coincidence factor," which appears to be related to assumptions about the number of customers per transformer. The assumed numbers of customers per transformer and coincidence factors used by the Company in its allocation are listed in Table 1 below.

Table 1

Company assumed values for the number of customers per transformer and coincidence factors

	Cust/Transformer	Coincidence Factor
Residential Sch 1	6.06	0.76
General Large Dist. Sch 6	1.00	1.00
General +1 MW Sch 8	1.00	1.00
Street & Area Lighting Sch. 7,11,12	1.00	1.00
Irrigation Sch 10	1.00	1.00
Traffic Signals Sch 15	1.00	1.00
Outdoor Lighting Sch 15	1.00	1.00
General Small Dist. Sch 23	2.56	0.86
Mobile Home Park Sch 25	1.00	1.00

Q. Do you have any problems with this allocation of transformers?

A. Yes. The implication is that there is more diversity in Schedule 1 and Schedule 23 than in other classes, but the basis for the Company assumed "coincidence factors" is unclear.

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

A. These changes are listed below:

- The F10 allocator is modified by removing the weighting of the 12 CPs;
- The assumed split between primary and secondary plant is changed from 43/57 to 50/50;
- Secondary plant is allocated to Streetlighting and Outdoor Lighting, and to 5% of the load on Schedule 6; and
- The allocation of Accounts 920, 921, and 922 is based on a labor allocator.

Q. What are the results of these various modifications to the Company's revenue requirement and cost of service study?

A. The major shifts resulting from these modifications are between residential customers and other classes. The use of the unweighted F10 and the changed primary/secondary split of Account 365 increase the residential class rate of return, while the modified allocation of A&G decreases the residential class rate of return. The total result is a very small increase to the residential rate of return, small decreases to most other classes, and slightly larger decreases to the Schedule 12 lighting classes. Table 2 below summarizes the changes to rates of return. Table 3 shows the impact on class calculated deficiencies, again based on the Company's revenue requirement.

Table 2

Rates of Return Reflecting Division Adjustments to Class Allocation

	Original 1	Unweighted F10 2	920-922 Labor Allocator 3	50/50 Sec Pri Acct 365 4	Allocator F22a Acct 365 5	All Changes 6	Cumulative Changes Col 6 – Col 1
Utah	5.80%	5.80%	5.80%	5.80%	5.80%	5.80%	0.00%
Residential Sch 1	5.51%	5.56%	5.45%	5.54%	5.52%	5.54%	0.03%
General Large Dist. Sch 6	7.11%	7.10%	7.15%	7.07%	7.09%	7.08%	-0.02%
General > 1 MW Sch. 8	5.66%	5.62%	5.71%	5.63%	5.66%	5.63%	-0.03%
Street & Area Sch. 7,11,12	14.86%	14.71%	14.32%	14.85%	14.86%	14.17%	-0.69%
General Transmission Sch 9	4.17%	4.09%	4.25%	4.16%	4.17%	4.18%	0.01%
Irrigation Sch 10	4.20%	4.20%	4.24%	4.16%	4.20%	4.19%	-0.02%
Traffic Signals Sch 12TS	5.87%	5.82%	5.52%	5.85%	5.72%	5.33%	-0.53%
Outdoor Lighting Sch 12OL	19.62%	19.20%	19.64%	19.60%	18.20%	17.94%	-1.68%
General Small Dist. Sch 23	6.98%	6.99%	6.95%	6.99%	6.99%	6.98%	0.00%
Mobile HomePark Sch 25	3.57%	3.61%	3.63%	3.54%	3.57%	3.63%	0.06%
Industrial Contract A	2.93%	2.88%	3.02%	2.93%	2.93%	2.97%	0.03%
Industrial Contract B	0.81%	0.74%	0.89%	0.81%	0.81%	0.82%	0.01%
Industrial Contract C	3.08%	2.95%	3.17%	3.08%	3.08%	3.04%	-0.04%

Table 3

RMP Revenue Requirements with Allocations Reflecting Division Adjustments to Class Allocation

	Original Rev. Req.	Unweighted F10 Rev. Req.	920-922 Labor Allocator Rev. Req.	50/50 Sec Pri Acct 365 Rev. Req.	Allocator F22a Acct 365 Rev. Req.	All Changes Rev. Req.	Cumulative Changes % Change
Utah	1,883,997,523	1,883,997,523	1,883,997,523	1,883,997,523	1,883,997,523	1,883,997,523	0.00%
Residential Sch 1	722,425,697	720,508,139	723,743,508	721,611,769	722,148,818	720,762,309	-0.23%
General Large Dist. Sch 6	502,763,454	503,071,109	502,160,384	503,410,112	503,051,398	503,381,876	0.12%
General > 1 MW Sch. 8	158,828,655	159,117,458	158,618,342	159,016,363	158,828,741	159,096,929	0.17%
Street & Area Sch. 7,11,12	12,559,849	12,598,928	12,696,797	12,561,239	12,559,816	12,737,313	1.41%
General Transmission Sch 9	256,797,688	257,586,225	256,211,764	256,798,587	256,798,099	256,996,544	0.08%
Irrigation Sch 10	14,836,136	14,809,266	14,821,090	14,861,643	14,836,158	14,820,867	-0.10%
Traffic Signals Sch 12TS	583,723	584,655	588,904	584,068	586,497	592,678	1.53%
Outdoor Lighting Sch 12OL	1,028,598	1,037,321	1,028,159	1,028,898	1,049,179	1,055,699	2.63%
General Small Dist. Sch 23	133,664,566	133,658,724	133,782,267	133,613,700	133,629,475	133,692,172	0.02%
Mobile HomePark Sch 25	1,054,948	1,052,308	1,052,907	1,056,523	1,054,950	1,051,902	-0.29%
Industrial Contract A	13,075,655	13,112,586	13,045,177	13,075,720	13,075,683	13,081,932	0.05%
Industrial Contract B	38,400,777	38,759,956	38,333,121	38,400,994	38,400,876	38,689,364	0.75%
Industrial Contract C	27,977,780	28,100,849	27,915,105	27,977,907	27,977,836	28,037,939	0.22%

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 previous case, 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; and
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.

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 RMP modified its load research approach in this case, and does this fully respond to the Workgroups' findings?

A. RMP has updated its load research to include the 2008 replacement samples for Schedule 6 and Schedule 23. While this addresses the Workgroups' findings that the samples were out-of-date, it does not address the two other major issues raised by the Workgroups: that the sample design itself does not fully capture within-class variability and that the load research data needs to be weather normalized before it is used to determine class allocators.

Q. Could you explain what is meant by "sample design," and how this can affect the usefulness of the data resulting from the load research?

A. In this case, "sample design," means the process by which RMP chooses a representative cross-section of a class to act as a proxy for the class as a whole. Proper sample design allows the estimation of accurate statistics on the desired characteristics for the entire class, without the need for an exhaustive census. In this case, a 'stratified' random sample was employed, which requires more careful execution than a simple random sample. If any important 'stratification' variables were omitted from the design, the sample could be biased, rendering the data from the load research sample much less useful.

In this case, peak load is a characteristic of major interest, but it is not possible to stratify directly on customer peak load because this information does not exist. The Workgroup concluded that the sample in this case should have been stratified by the variability in each customer's load, which would provide more information about peak load, as well as their overall average load. Without this further stratification, it is possible that the load research data in this case has been biased.

Q. How is load research data used to estimate class peaks?

A. The Company employed a simple methodology to estimate class peaks from the load research sample, prior to any adjustments. For each class, the Company calculated the average load for each stratum by hour. It then weighted those averages according to their stratification methodology to find the overall class average usage for each hour, and multiplied by the population of that class to find the overall class usage. The hourly usage estimates were then used to calculate the class monthly and yearly peaks.

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. The projections calculated from the load research data did not closely match the forecast peaks, and in some cases were off by over 20%. Specific problem months were October 2009 (13% difference), December 2009 (12% difference), March 2010 (12% difference), April 2010 (8% difference) and May 2010 (21% difference). Furthermore, the peaks calculated from the load research data and the peaks calculated from the jurisdictional forecasts often differed in timing by as much as 22 days during these months.

Q. Did the Workgroup address how the load research data estimates of peak loads should be adjusted to meet the system forecast peaks?

A. The Workgroup approved a stepped adjustment process, whereby the Company would weather-normalize the load research data, choose new peak hours for cases where the load research data differed from the jurisdictional data by more than 10%, and then if there was still a difference of more than 5%, further adjust the peaks by a "calibrating adjustment." The Company followed this procedure, with the exception that it did not weather-normalize loads.

Q. How did the load research data in the 3/10/2011 discovery responses compare to RMP's projected peak loads in this case?

A. The load research data peak projections did not closely match the forecast peaks in this rate case. Specifically, October, December, March, April, and May were significantly different and needed adjustment.

Q. How did RMP then adjust its load research peak data?

A. RMP adjusted its peaks in a 2-step process. First, for months with a difference greater than 10% between the load research peaks and the jurisdictional forecast peaks, RMP used load research data from a different time than the actual peak: generally the forecast peak hour on the actual peak day. Then, for months where the difference between the forecast and the load research was still greater than 5%, RMP applied a simple scaling factor to all class loads to bring the total within 5% of the jurisdictional forecast loads. For May they chose a different day: the May actual peak was May 6th at 9am, but the forecast peak was May 15th at 4pm. The difference between forecast and actual was 26%, so RMP chose a new peak: May 18th at 4pm. This new 'Actual' peak still differed from the forecast by 19.51%, so the estimated class loads were increased by a constant scaling factor until this difference dropped to 5.26%.

Q. Were these adjustments appropriate?

A. While RMP followed most of the adjustment process recommended by the Workgroup, it failed to weather-adjust the load research data before making comparisons. As a result, RMP may have under-adjusted weather-sensitive classes by giving all classes the same scaling factor. By using a scaling factor, with no weather normalization, weather-sensitive classes are treated the same as weather-insensitive classes. This ignores the true drivers of the system peak, and may result in under-adjustments of some classes, and over-adjustments of others.

Q. Has the Company estimated the peak loads of the Irrigation class appropriately?

A. No. The load of the irrigation class has been estimated by a time series regression of irrigation usage per customer. This is a load that is related to rainfall as well as to temperature and is clearly difficult to forecast.

Q. Does the difficulty of forecasting the peak load of the irrigation class totally invalidate the allocation of costs to the irrigation class?

A. Not totally, because only a portion of costs are allocated on the basis of peak loads. I tested the sensitivity of the Irrigation results to the peak load estimates for the class, and found that if the peak load had been overestimated by 20%, the Irrigation class' percentage deficiency would have been higher than the residential percentage but lower than Schedule 9. Of course, if the peak load had been underestimated, the Irrigation class rate of return would have been lower than the Company's model showed.

IV. RATE DESIGN

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

A. Yes. First, the Company is proposing an unreasonable increase in the residential customer charge. Second, its approach to time of use rates results in rates that do not live up to the potential of such rates to create more efficient behavior. Third, its uniform percentage increases to various components of many rates does not take into consideration underlying costs and may not result in 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 $3.75 per month to $10.00 month, an increase of 167%.

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

A. Mr. Griffith testifies that the current residential customer charge does not recover what he defines as the "fixed costs" of serving residential customers. He offers two alternative definitions of customer costs intended to justify the proposed customer charge. The first version, labeled "UPSC Methodology Modified", results in average customer costs of $10.90 per month, and the second version, labeled "100% Cost Based", results in a monthly customer cost of $23.56 per month.

Q. Please comment on the UPSC Methodology Modified calculation.

A. First, it appears that the Company's nomenclature is disingenuous, as the Company has added considerable additional costs to those in the methodology approved in the past by the Utah Public Service Commission ("Commission"). The approved methodology includes the return on and depreciation expense associated with meters and service drop plant, which are I believe almost universally accepted as customer related. It also includes the expense of reading meters (Account 902.1) and billing expense (Account 903.2).

The Company's "modifications" to the Commission's methodology include adding what it calls "Retail" expenses, which are basically all of Accounts 901 -919. This process immediately double-counts Meter Reading expense, as it is included alone through the Commission's methodology and again in the Company's "Retail" expense. The Company also adds in to this calculation what it calls the customer-related portion of the cost of transformer plant.

Q. Do you think any of these proposed changes are justified?

A. For the most part, I do not. The Company is clearly trying to recover more "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 provide any evidence that these should all be included in customer costs.

This addition of retail costs to the approved calculation also creates a clear error, in that meter reading costs have been counted twice, once as a separate cost and again as they are included the retail costs. With regard to other expenses in the 900 accounts, an argument could be made that some customer accounting costs (in addition to billing costs) vary with the numbers of customers on the system. In these days of complex automated accounting systems, this is a debatable question, but including some additional expenses in customer costs might be reasonable. Including some part of transformer costs in the calculation of customer costs is not reasonable.

Q. What is the basis on which the Company claims that a portion of transformer costs are customer costs?

A. Mr. Griffith points to Mr. Paice's marginal cost study as backup for this treatment of transformers. The marginal cost study includes 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. Mr. Paice interprets the intercept from this equation as "commitment related" cost, which he evidently considers a customer cost.

Q. Has Mr. Paice estimated the marginal cost of a transformer, and has he calculated a customer-related transformer cost?

A. No to both questions. 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 any part of the transformer cost is customer related. Mr. Paice's calculation will be discussed further under Section V, Discussion of Company's Marginal Cost Study.

Q. What is the basis on which the Company calculates its even larger estimate of customer costs, the so-called "100% Cost Based" version?

A. The Company adds the cost of poles and conductors and also includes the full cost of transformers to the meter and service costs and the expenses that were included in the UPSC Modified method.

Q. Is this an appropriate basis for a customer charge?

A. No, it is not. The Company might like to collect virtually all of its plant costs through monthly fixed charges, but 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 not providing appropriate price signals. Even the Company's very flawed marginal cost study indicates that there are marginal costs associated with transformers, poles and conductors. To collect all of these costs through a fixed monthly charge means that customers will not know that as load increases, delivery costs increase as the Company will have to add more distribution plant.

Q. Have you calculated the residential customer cost on the basis of the Commission's approved methodology?

A. Yes. I have done this using the Return on Equity ("ROE") of 10% recommended by the Division, and also based on the Company's original filing. The computation using the Division ROE is shown below in Table 4. The costs in Account 903.2 in the test year were provided in response to DPU DR 29.1. The same computation using the Company's revenue requirement produced a before tax customer cost of $3.99.

Table 4

Residential customer costs using UPSC methodology, Division ROE

Description	Residential - Sch 1	
	after tax	before tax
Billing Service Revenues (Account 456)	-	-
Customer Billing & Accounting Expense (Account 903.2)	5,735,996	5,735,996
Meter Reading, (Account 902.1)	4,497,560	4,497,560
Meters - Depreciation Expense	1,881,619	1,881,619
Service Drop - Depreciation Expense	3,272,815	3,272,815
Service Drop Plant, Account 369	175,245,001	175,245,001
Meter Plant, Account 370	59,075,450	59,075,450
Meters - Accumulated Depreciation	(21,772,247)	(21,772,247)
Service Drop - Accumulated Depreciation	(48,080,623)	(48,080,623)
Total Rate Base	164,467,580	164,467,580
Return on Rate Base @ target ROR	13,130,220	18,367,395
Total Costs (less Billing Service Revenues)	28,518,210	33,755,385
Average Customers	719,832	719,832
Monthly Customer Charge	**$3.30**	**$3.91**

Q. This methodology would allow very little increase in the customer charge for it to be cost-based. What would an appropriate customer charge be if the Commission approved the inclusion of all of what the Company labels "retail costs"?

A. If all of the costs in the 900 accounts, the Company's "retail costs," are included, the meter reading costs in Account 902.1 should not be added in separately because they are included in the retail category. Table 5 below makes this calculation, using the Division recommended ROE. This approach would justify a customer charge of approximately $6.81, compared to the Company's proposed $10 customer charge.

Table 5

Alternative residential customer cost calculation using full retail costs, ROE=10%

Description	Residential - Sch 1	
	after tax	before tax
Billing Service Revenues (Account 456)	-	-
Retail *	35,292,011	35,292,011
Meter Reading included in Retail	0	-
Meters - Depreciation Expense	1,881,619	1,881,619
Service Drop - Depreciation Expense	3,272,815	3,272,815
Service Drop Plant, Account 369	175,245,001	175,245,001
Meter Plant, Account 370	59,075,450	59,075,450
Meters - Accumulated Depreciation	(21,772,247)	(21,772,247)
Service Drop - Accumulated Depreciation	(48,080,623)	(48,080,623)
Total Rate Base	164,467,580	164,467,580
Return on Rate Base @ target ROR	13,130,220	18,367,395
Total Costs (less Billing Service Revenues)	53,576,665	58,813,840
Average Customers	719,832	719,832
Monthly Customer Charge	**$6.20**	**$6.81**

Q. You mentioned that the Company's proposal regarding residential customer costs is flawed in its failure to consider bill impacts, even if the proposal were not theoretically flawed. Please discuss.

A. One of the basic principles of rate design is that of gradualism – i.e. of taking care not to increase one group of customers much more than others. The Company proposed increase in the customer charge of $6.25 is a 167% increase to the current $3.75 charge. This obviously has much more of an impact on small bills than on large bills. The Company's rate design would increase a 100 kWh bill by 24%, but a 3000 kWh bill would increase by only 8%. Mr. Paice's Monthly Billing Comparison does not directly show these differences, because the only percentage increases shown are those resulting from the energy charges.

The Company claims in response to OCS DR 9.3 that this customer charge increase does not violate the principle of gradualism. "It meets the principle of gradualism because the Company has been proposing to increase the residential customer charge to a cost based level since the $1.00 residential customer charge was first included on customer bills in Docket No. 84-035-01, on July 1, 1985, a period of more than 25 years." Whether the Company has been proposing something for 1 year or 25 years does not change the basic fact that a more than doubling of a significant rate component is not consistent with gradualism.

The current customer charge of $3.75 is only slightly below the customer cost resulting from the Commission's definition of customer costs of $3.91. The Company's claim that they are attempting to increase the customer charge to a cost-based level assumes that the

Commission accepts the Company's new definition of customer costs which includes many additional expenses and a portion of the cost of transformers. I do not think that transformer costs should be included in this definition. I have not seen definitive evidence that all "retail costs" are caused directly by the numbers of customers on the system. If the Company were to provide such evidence, it would have provided justification for a revised estimate of customer costs. Whether a higher customer charge was advisable would then depend partly on considerations of bill continuity.

B. Proposed Time of Use Rates Should Be Modified

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 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.

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.

Q. What is the basis for the TOU rate design?

A. The residential time of use rates were introduced in 1998. They were modified in 2004 to essentially their current structure. There was a review of the residential TOU rate in 2005. Since that time, there does not seem to have been an attempt to consider the efficacy of the rates or their design. The current rates are the result of changing all time of use energy charges and credits by the same percentage applied to the standard rates, through a number of cases, and the Company proposes to do the same thing in its proposed rates for this case.

Q. Why is it you believe these rates are not effective tools to encourage load shifting?

A. The major problem is that the potential rewards for shifting load are very small. In fact the average per kWh charge for both residential (Sch-2) & C&I TOU (Sch-6A) customers are <u>higher</u> than their non-TOU rate equivalents (Schedules 1 and 6, respectively).

Part of the reason is that the TOU customers are smaller usage customers than the non-TOU customers. The customer charge is thus spread over fewer energy units. However, I would have expected that this would have been compensated for by savings in energy rates, which is not the case.

I have estimated that for the average non-TOU customer, with an average load shape, the TOU rates are more expensive than the non-TOU rates. Under the Company's proposed rates, a residential customer with a typical load shape looking to move to a TOU rate would find that the energy portion of their bill would increase by about 0.2 cents/kWh during the summer months (when the TOU rate applies) compared to staying on the non-

TOU rate. This is illustrated by Table 6 below, which shows the projected summer energy revenues for Schedule 1 under the Company's proposed rates and the energy revenues if all of Schedule 1 moved to Schedule 2, which has a peak penalty and off-peak credit. The typical customer split between peak and off-peak energy use was provided in response to discovery request DPU 21.1. Another way of putting this is that the proposed TOU rate is not revenue neutral to the typical customer.

Table 6

Revenue impact of Schedule 1 customers switching to Schedule 2.

Sch-1	Forecasted kWh	Proposed cents/kWh	Energy Revenue
First 400 kWh (May-Sept)	1,283,318,788	8.3117	$ 106,665,608
Next 600 kWh (May-Sept)	1,058,610,469	10.2389	$ 108,390,067
All add'l kWh (May-Sept)	579,928,183	12.7351	$ 73,854,434
		TOTAL:	$ 288,910,109
		$/kWh:	$ 0.0989

Sch-2	Forecasted kWh	Proposed cents/kWh	Energy Revenue
Peak Adder	797,056,697	4.3762	$ 34,880,795
Off-Peak Adder	2,124,800,743	-1.4014	$ (29,776,958)
First 400 kWh (May-Sept)	1,283,318,788	8.3117	$ 106,665,608
Next 600 kWh (May-Sept)	1,058,610,469	10.2389	$ 108,390,067
All add'l kWh (May-Sept)	579,928,183	12.7351	$ 73,854,434
		TOTAL:	$ 294,013,947
		$/kWh:	$ 0.1006

Difference in Revenue between Schedule 1 and 2:	$ 5,103,838
Difference/kWh:	$ 0.00175

The 2005 report on the residential TOU rate stated that customers could save money compared to the standard rate if at the same usage level they used less than 24% of their usage during on-peak hours during the summer months. Currently average customers use about 27% of their usage during these on-peak hours. My analysis of the current rate shows that a customer that uses 3% less on peak than the average customer, i.e. 24 % of their total summer usage, saves only 0.01%, or a total of about $0.11 per month. This small savings amount is unlikely to incent customers to either shift use or to go onto the rate.

A similar analysis shows that commercial customers moving from Schedule 6 to the Schedule 6A TOU rate would also see their energy charges and bills increase. An increase in energy charges alone would be expected given that the demand charges for Schedule 6A are lower than Schedule 6, but even when taking this into account, the annual charges are about 0.9 cents/kWh higher for customers switching to a TOU rate. I have calculated and compared the demand charge revenues that would be paid for customers on both Schedule 6 and 6A. These calculations are illustrated in Table 7 below. (The peak/off-peak energy use split was estimated using the Company's response to data request DPU 14.18.)

Table 7

Revenue impact of Schedule 6 customers switching to Schedule 6A

Sch-6	Forecasted kWh	Proposed cents/kWh	Energy Revenue
kWh (May-Sept)	2,629,252,324	3.7528	$ 98,670,581
kWh (Oct-Apr)	3,261,389,982	3.461	$ 112,876,707
		TOTAL:	$ 211,547,288
		TOTAL/kWh:	$ 0.036

Sch-6A	Forecasted kWh	Proposed cents/kWh	Energy Revenue
On-Peak kWh (May - Sept)	1,505,709,126	11.5406	$ 173,767,867
Off-Peak kWh (May - Sept)	1,123,543,198	3.4745	$ 39,037,508
On-Peak kWh (Oct - Apr)	1,845,435,827	9.6467	$ 178,023,658
Off-Peak kWh (Oct - Apr)	1,415,954,155	2.9142	$ 41,263,736
		TOTAL:	$ 432,092,770
		TOTAL/kWh:	$ 0.073

Difference in Energy Revenues from Switching to TOU Rates:	$ 220,545,481
Difference/kWh:	$ 0.03744
Expected Difference due to Change in Demand Charge Revenue:	$ 170,076,997
Difference in Energy Revenues Accounting for Difference in Demand Charge:	$ 50,468,484
Difference/kWh:	$ 0.00857

Q. Does the proposed TOU rate design conform to the stated goals for Demand Side Management ("DSM") in the Company's IRP?

A. No. In response to discovery request DPU 10.19, the Company stated that it referenced TOU rates under Class 3 DSM in the 2008 IRP and that these rates were put in place to "encourage customers to reduce on-peak usage." Designing TOU rates that would penalize customers from switching from a flat rate to a TOU rate discourages customers from selecting TOU rates. Without customers, these rates will not be effective tools to encourage peak load reductions.

Q. For the small number of customers that have enrolled on TOU rates, have the rates been effective in reducing peak load?

A. Data provided by the Company as summarized in Table 8 below shows that on average TOU customers have a smaller portion of their load on-peak compared to their non-TOU counterparts. Although it is impossible to know how much of this difference is due to load switching, this is evidence that TOU rates can incentivize peak load reductions on the Company's system. (Note that the amount of peak period use for residential customers is much smaller than for commercial customers because the peak period for residential customers is much shorter: it is only 1 PM to 8 PM as opposed to 7 AM to 11 PM for commercial customers.)

Table 8

Peak/off-peak energy use for residential and commercial customers with and without TOU rates

Customer Type	Schedule	Rate Type	Summer		October-April		Source
			% On Peak	% Off-Peak	% On Peak	% Off-Peak	
Residential	1	Non-TOU	27%	73%	N/A	N/A	DPU DR 21.1
Residential	2	TOU	22%	78%	N/A	N/A	Billing Determinants provided in WRG-5
Commercial	6	Non-TOU	57%	43%	57%	43%	DPU DR 14.18
Commercial	6A	TOU	49%	51%	52%	48%	Billing Determinants provided in WRG-5

Q. Do we know what the cost difference is between peak and off-peak hours?

A. I do not have an estimate of the <u>total</u> cost difference. Currently the difference in energy costs, which I can estimate, is not large. Based on the proxy hourly prices provided by PacifiCorp's Open Access Same-time Information System ("OASIS"), it appears that the energy price difference is about 7 mills ($.007) per kWh. However, marginal transmission and marginal distribution costs will also be higher in the on-peak hours, and marginal generation costs are primarily driven by peak load. These three cost elements will create a much larger total difference between peak and off-peak marginal costs. Table 9 below reflects the unweighted average of the PacifiCorp OASIS energy prices during peak and off-peak hours.

Table 9

Unweighted average PacifiCorp energy prices

Summer	**Peak 1-8pm**	Avg. Peak	$	36.27
		Avg. Off-Peak	$	29.38
All Months	**Peak 7am-11pm**	Avg. Peak	$	37.20
		Avg. Off-Peak	$	29.89
Summer	**Peak 7am-11pm**	Avg. Peak	$	36.27
		Avg. Off-Peak	$	26.11
Winter	**Peak 7am-11pm**	Avg. Peak	$	37.87
		Avg. Off-Peak	$	32.65

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

A. I recommend that these rates be modified so that customers on the TOU rates, with their lower on-peak use, pay noticeably less on an average basis. I would recommend aiming at a percentage savings to summer bills that would be expected to impact behavior. This will mean that revenues from the TOU rates will be somewhat lower, and this will require that the regular rates be increased to make up the difference. Given how few customers are on the TOU rates, this will have an insignificant impact on the regular rates.

Q. Have you actually calculated what such rate might look like?

A. Yes. I started by developing a revenue neutral rate, based on the Company's requested revenue requirement. For residential customers, I calculated new peak and off-peak TOU adders such that a) the ratio of peak/off-peak energy rates equals the 2010 peak/off-peak market prices for the summer months (about 1.2 according to the table above) and b) the projected extra revenue collected by the Company during peak hours due to the peak adder would exactly offset the credit paid by the Company during off-peak hours due to the off-peak credit. This would both send accurate price signals to customers regarding the costs-to-serve during peak hours and eliminate any disincentive for customers to switch to a TOU rate because of feared bill increases. The new adders are found in Table 10 below.

Table 10

Proposed peak and off-peak rate adders with total revenues equal to non-TOU rates

Sch-2 with Equal Revenue	Forecasted kWh	Alternative cents/kWh	Energy Revenue
Peak Adder	797,056,697	1.58	$ 12,630,588
Off-Peak Adder	2,124,800,743	-0.5944	$ (12,630,588)
First 400 kWh (May-Sept)	1,283,318,788	8.3117	$ 106,665,608
Next 600 kWh (May-Sept)	1,058,610,469	10.2389	$ 108,390,067
All add'l kWh (May-Sept)	579,928,183	12.7351	$ 73,854,434
		TOTAL:	$ 288,910,109

With this rate, the savings to customers with 24% of their usage on-peak would be 0.72%, and the savings with 22% on peak would be 1.16%.

This saving is still very small. To produce greater savings, the off-peak adder could be increased. If this were not balanced by an increase in the peak adder, the rate would produce less revenue, but customers with 22% of their load on peak would see a 3% bill reduction. This rate is still a revenue neutral rate, and is presented in Table 11 below. To provide much greater savings would mean that Schedule 2 would produce less revenue which would have to be recovered from another rate.

Table 11

Alternative peak and off-peak rate adders with total revenues equal to non-TOU rates and peak/off-peak price ratio reflective of current Schedule 2 TOU rates.

Sch-2 with Equal Revenue	Forecasted kWh	Alternative cents/kWh	Energy Revenue
Peak Adder	797,056,697	4.13	$ 32,907,181
Off-Peak Adder	2,124,800,743	-1.5487	$ (32,907,181)
First 400 kWh (May-Sept)	1,283,318,788	8.3117	$ 106,665,608
Next 600 kWh (May-Sept)	1,058,610,469	10.2389	$ 108,390,067
All add'l kWh (May-Sept)	579,928,183	12.7351	$ 73,854,434
		TOTAL:	$ 288,910,109

V. DISCUSSION OF COMPANY'S MARGINAL COST STUDY

Q. Mr. Paice has 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. These will result in an understatement of the marginal cost of generation capacity. I also find problems with some of the methods of estimating different components of marginal distribution costs. In general, marginal costs are defined as the change in total costs given a small change in output or load; in the short run, only variable costs change; in the long run, fixed costs also can change.

Q. Are there components of the marginal cost study that do comport with normal marginal cost practices?

A. Yes. The marginal transmission cost methodology does attempt to estimate the relationship between transmission investment and growth in peak load. It does so by identifying growth-related forecasted transmission expenditures and forecasted load. Transmission investment on a per kW of peak load is then annualized by a carrying charge, and increased by an adder that reflects administrative and general costs and also annual O&M expenses. This approach assumes that additional investment will require additional expenses. The Company's methodology does not include an explicit adder for general plant.

Q. Is the estimation of the marginal cost of generating capacity also consistent with typical marginal cost calculations?

A. The marginal cost of generating capacity does not include the cost impact of reserves, which will understate the marginal capacity cost. When peak load grows, a utility must provide additional capacity to meet not only that load increment but also the additional reserve required by the larger load.

The Company's rationale for not including reserves is that "such an adder is not part of the Utah Commission approved methodology for determining avoided costs." (Data Response OCS DR 10.20) Generation marginal costs do not include an explicit A&G expense loading factor. The Company's rationale for this exclusion is that its marginal generation costs are based on the avoided cost study, which does not include an A&G expense loading factor (Data Response OCS 10.25). The generation capacity cost estimates in the avoided cost study do include corporate overheads and O&M, according to the response to OCS DR 33.5.

Appropriately including reserves in the calculation would increase the estimate of marginal generation capacity cost.

Q. Earlier in your testimony, you stated that Mr. Paice's estimation of the marginal cost of transformers was not correct. Will you please elaborate on this estimation methodology?

A. As noted above, the long run marginal cost of distribution plant should reflect the change in cost as the most relevant peak demand changes. Mr. Paice has calculated the statistical relationship between the cost of a transformer and the size of the transformer in a single year. While this relationship may be important for engineering and design, it is not a measure of the marginal 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. Mr. Paice's equation tells us simply that the cost of the transformer does not increase linearly with the size of the transformer; that cost increases at a slower rate. The intercept of this equation is not a marginal customer cost. The coefficient of transformer size is treated as the investment per KVA, and is then annualized. The annualized coefficient of the transformer size in the equation is not a marginal capacity cost.

Q. Does there appear to be a general problem with Rocky Mountain Power's estimation of marginal distribution costs?

A. Yes. Portions of the marginal cost study do not estimate how costs will change as peak load and energy change but instead are analyses of current relationships between costs and various items. The transformer analysis discussed above is one example. Also, what is called the Circuit Distribution Model seems to be simply an embedded plant analysis. It estimates the relationship between investment in poles and conductors per class and the number of customers, average size of customers, and average kW per customer, based on a hypothetical distribution circuit.

This would be similar to claiming that the coefficient based on the relationship between the cost and size of a generating plant resulted in the marginal cost of additional load. It clearly does not.

Q. How could marginal distribution capacity be estimated in a manner that would reflect the cost of growth in load

A. The marginal cost of distribution capacity relative to increases in peak load (probably non-coincident peak load) could be estimated by a regression comparing growth-related distribution investment (adjusted for cost inflation, normally by the Handy-Whitman index) to peak loads over a period of time. This incremental investment value would then be annualized.

Q. Do you have any idea of how RMP's computed marginal costs would change if your recommendations were followed?

A. I do not have an estimate of such a change. It is my expectation that the Company's methodologies have tended to understate marginal cost.

VI. RATE SPREAD

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

A. The Company proposed to allocate the rate increase by setting 4 discrete percentage increases, which are either lower or higher than a midpoint increase of 14.6 %. Classes whose percentage deficiency, as calculated by the Company's cost of service study, is close to this midpoint, which includes the Residential class and Schedule 8, will receive this midpoint increase. Schedules 6 and 23 are assigned an increase of 12.6%. Mr.

Griffith proposes to mitigate the potential increases to Schedule 9 and the Irrigation class, so that they receive increases of 16.6% and 18.6%, respectively, which are less than would be justified by the allocated cost of service study.

Q. Have you reviewed the Division's recommended revenue requirement, and should this change the allocation of the revenue increase across rate classes?

A. Yes to both questions. The Division is recommending a revenue requirement that would result in an average increase to all classes of 7.95%. Since the revenues of two special contract customers cannot be increased, the average increase to other customers is 8.22%.

The range of percentage deficiencies, based on the Division's recommended revenue requirement and the allocation changes that I have made, is roughly from -17% to +19%. However, most C&I classes and the residential class show deficiencies between 3.5% and 12 %. 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 12 below shows class deficiencies, rates of return, and the rate of return index based on the Division's cost of service.

Table 12

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	623,014,366	6.22%	0.93	684,258,971	61,244,605	9.83%
6	General Service - Large	459,953,820	7.99%	1.20	476,002,980	16,049,160	3.49%
8	General Service - Over 1 MW	138,876,686	6.60%	0.99	150,243,550	11,366,864	8.18%
7,11,12,13	Street & Area Lighting	13,819,556	14.90%	2.24	12,312,179	(1,507,377)	-10.91%
9	General Service - High Voltage	215,589,840	5.37%	0.81	241,828,179	26,238,339	12.17%
10	Irrigation	12,157,883	4.96%	0.74	14,017,353	1,859,470	15.29%
15	Traffic Signals	521,280	5.96%	0.89	567,953	46,673	8.95%
15	Outdoor Lighting	1,218,133	19.49%	2.92	1,004,999	(213,134)	-17.50%
23	General Service - Small	121,790,447	7.82%	1.17	126,567,042	4,776,595	3.92%
25	Mobile Home Parks	831,396	4.35%	0.65	992,803	161,408	19.41%
SpC	Customer A	10,557,777	4.14%	0.62	12,318,078	1,760,301	16.67%
SpC	Customer B	30,307,371	2.36%	0.35	36,405,944	6,098,573	20.12%
SpC	Customer C	22,942,659	4.30%	0.65	26,418,868	3,476,209	15.15%
	Total Utah Jurisdiction	1,651,581,214	6.67%	1.00	1,782,938,899	131,357,685	7.95%

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

A. I recommend that rate increases should be capped and also that rate decreases should be capped. This requires a process where the initial rate increases are either set at the class deficiency or are held down by a cap or, in the case of rate decreases, set at lower decreases than called for in the cost of service study. There is also additional revenue shortfall reflecting the lack of an increase to the two special contract customers. The net shortfall that is created by this methodology then must be spread across other customer classes.

Specifically, I recommend that initial rate increases be capped at 150% of the system average increase, or 12.33%, and rate decreases be held to no more than -5%. I have allocated the missing revenue dollars to most classes that receive rate increases. This will necessarily result in the final increase to a number of classes being greater than the capped percentage, since the shortfall must be recovered from some customers.

In addition to the formulaic approach discussed above, I made a discrete adjustment to the Irrigation class, to reflect my concern over the peak load estimate for this class. I decreased their increase by $100,000 and shifted these dollars to Schedule 23, which is still receiving a very small percentage increase.

Table 13 below shows this allocation of revenues and the resulting class increases, in dollars and on a percentage basis.

Table 13

Rate Spread Based on Division Revenue Requirement

Schedule No.	Description	Capped Increase	Shortfall	Decreases Capped at 5%	Shortfall Allocator	Allocated Shortfall	Class Increase	New % Increase
1	Residential	61,244,605	0		39.94%	(3,788,438)	65,033,043	10.44%
6	General Service - Large	16,049,160	0		29.49%	(2,796,896)	18,846,057	4.10%
8	General Service - Over 1 MW	11,366,864	0		8.90%	(844,484)	12,211,348	8.79%
7,11,12,13	Street & Area Lighting	(1,507,377)	0	816,399	0.00%	0	(690,978)	-5.00%
9	General Service - High Voltage	26,238,339	0		13.82%	(1,310,963)	27,549,302	12.78%
10	Irrigation	1,498,780	(360,690)		0.00%	0	1,398,780	11.51%
15	Traffic Signals	46,673	0		0.03%	(3,170)	49,842	9.56%
15	Outdoor Lighting	(213,134)	0	152,228	0.00%	0	(60,907)	-5.00%
23	General Service - Small	4,776,595	0		7.81%	(740,586)	5,617,180	4.61%
25	Mobile Home Parks	102,491	(58,916)		0.00%	0	102,491	12.33%
SpC	Customer A	1,301,525	(458,776)		0.00%	0	1,301,525	12.33%
SpC	Customer B	0	(6,098,573)				0	
SpC	Customer C	0	(3,476,209)				0	
	Total Utah Jurisdiction	120,904,521	(10,453,164)	968,626			131,357,685	7.95%

Q. Does this conclude your testimony?

A. Yes, it does.