Exhibit No.___(RRS-1Tr)
Docket Nos. UE-140762 *et al.*
Witness: Robert R. Stephens

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY, Respondent.	DOCKET NOS. UE-140762 and UE-140617 *(consolidated)*
In the Matter of the Petition of PACIFIC POWER & LIGHT COMPANY, For an Order Approving Deferral of Costs Related to Colstrip Outage	DOCKET NO. UE-131384 *(consolidated)*
In the Matter of the Petition of PACIFIC POWER & LIGHT COMPANY, For an Order Approving Deferral of Costs Related to Declining Hydro Generation	DOCKET NO. UE-140094 *(consolidated)*

RESPONSIVE TESTIMONY OF ROBERT R. STEPHENS

ON BEHALF OF

BOISE WHITE PAPER, L.L.C.

October 10, 2014

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RESPONSIVE TESTIMONY OF ROBERT R. STEPHENS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Robert R. Stephens. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. WHAT IS YOUR OCCUPATION?

A. I am a consultant in the field of public utility regulation and a Principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. These are set forth in Exhibit No.___(RRS-2).

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of Boise White Paper, L.L.C. ("Boise"), a customer of PacifiCorp d/b/a Pacific Power & Light Company ("PacifiCorp" or the "Company").

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH THIS TESTIMONY?

A. Yes. I am sponsoring Exhibit No.___(RRS-2) through Exhibit No.___(RRS-8r).

Q. WHAT IS THE PURPOSE OF YOUR RESPONSIVE TESTIMONY?

A. I will address PacifiCorp's electric cost of service study and revenue allocation ("rate spread") issues. More specifically, with respect to cost of service, I will address alternatives to PacifiCorp's classification methodology and allocators for production-related costs and for transmission costs. I will also address PacifiCorp's rate spread proposal.

The fact that I do not address any particular issue should not be interpreted as tacit approval of any position taken by PacifiCorp.

I. SUMMARY

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My responsive testimony can be summarized as follows:

1. The Company's electric cost of service study filed in this case is reasonable in many respects. However, I have identified two significant changes that should be made in order for the cost of service study to more accurately measure the cost causation incurred by the various customer rate schedules. These relate to the classification and allocation of production and transmission costs.

2. With respect to the classification and allocation of production costs, I discuss the significant shortcomings of the "Peak Credit" or load factor classification method and recommend that it be discontinued. My recommendation is for production fixed costs to be allocated in a more traditional demand approach and for production variable costs to be allocated in a more traditional energy approach. If the Washington Utilities and Transportation Commission ("WUTC" or the "Commission") decides to retain the Peak Credit classification approach, I strongly recommend that the demand allocator be modified to more accurately address capacity cost causation.

3. Whether or not the Peak Credit or load factor classification is retained, I recommend use of the 4 Coincident Peaks ("CP") as a better measure of the demand component for allocating production costs, rather than PacifiCorp's proposed 200 hour measure, since PacifiCorp's load exhibits significant peaks. This allocator is also more strongly supported in the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("NARUC Manual"), which is widely relied upon in defining industry standards.

4. With respect to transmission system costs, I recommend use of the 12 CP demand allocation method rather than the Peak Credit or load factor classification method. 12 CP is a better measure of cost causation and is more consistent with industry norms.

5. Adjustment on these two allocation issues reveals significant class cost differences from the results of the PacifiCorp cost study. The differences are summarized and shown for each class rate schedule herein.

6. Regarding rate spread, in concept, I support PacifiCorp's proposed approach, but modify it somewhat to be less subjective and to guide the rate spread in the event PacifiCorp's full revenue requirement is not approved.

II. ELECTRIC COST OF SERVICE STUDY

Overview

Q. HOW ARE LARGE INDUSTRIAL CUSTOMERS AFFECTED BY THE PRICE OF ENERGY?

A. For many industrial customers, energy is a primary component of their costs. For some, it may be the most critical component. As such, rate stability and overall cost of electricity prices are vital to the economic health of large commercial and industrial customers in Washington – and to the economic health of Washington itself, as Washington industries compete in national and world markets. Furthermore, any cost of service study or rate design that misallocates costs to large customers will also result in unjust and unreasonable rates.

Q. PLEASE EXPLAIN THE BASIC STEPS FOR ESTABLISHMENT OF FAIR AND REASONABLE RATES?

A. The ratemaking process has three steps. First, we must determine the utility's total revenue requirement and whether an increase or decrease in revenues is necessary. Second, we must determine how the revenues are to be distributed among the various customer classes or schedules. A determination of how many dollars of revenue should be produced by each class is essential to obtaining the appropriate level of rates. This is called "revenue allocation" or "rate spread." Finally, individual tariffs must be designed to produce the required amount of revenues from each class of service and to send efficient price signals to customers.

The guiding principle at each step should be cost of service. In the first step – determining revenue requirements – it is widely agreed that the utility is entitled to a revenue increase only to the extent that its actual overall cost of service has increased. If current rate levels exceed the revenue requirement, a rate reduction is required. In short, rate revenues should equal a utility's actual cost of service. The same principle should apply in the last two steps. Each customer class should, to the extent practicable, produce revenues equal to the cost of serving that particular class. On some occasions, this may require a rate increase for some customer classes and a rate decrease for others. The standard tool for determining whether a class requires a rate increase or decrease is a class embedded cost of service ("ECOS") study, which shows the rate of return for each class of service. Ideally, rate levels should be modified so that each customer class provides approximately the same rate of return.

Finally, in designing individual tariffs, the goal is to base the rate design on the cost of service, so that each customer's rate tracks, to the extent practicable, the utility's cost of providing that service to the customers on the tariff.

Q. WHAT IS THE BASIC PURPOSE OF A CLASS ECOS STUDY?

A. The basic purpose of a class ECOS study is an empirical determination of the cost of serving classes of customers.

After determining the overall cost of service or revenue requirement, a class ECOS study is used to ascertain the cost of service among customer classes (i.e., a cost of service study shows how each customer class contributes to the total system cost). For example, when a class produces the same rate of return as the total system, it is returning to the utility revenues sufficient to cover the costs incurred in serving the class (including a reasonable authorized return on investment). If a class produces a below-average rate of return, it may be concluded that the revenues are insufficient to cover all relevant costs. On the other hand, if a class produces a rate of return above the average, it is paying revenues sufficient to cover the cost attributable to it and, in addition, is paying part of the cost attributable to other classes who produce a below average rate of return. The ECOS study is important because it shows the class revenue requirement as well as the rate of return under current and any proposed rates.

As a measurement or estimation tool, the ECOS study is not the step in which other factors, such as rate moderation or continuity, should be considered or allowed to influence the results. Those types of considerations are taken up in the revenue allocation and rate design steps.

Q. PLEASE COMMENT ON THE PROPER FUNDAMENTALS OF AN ECOS STUDY.

A. In all ECOS studies, certain fundamental concepts should be recognized. Of primary importance among these concepts is the functionalization of costs, as well as the classification of the nature of these costs as to whether they vary with the quantity of energy consumed, the demand placed upon the system, or the number of customers being served. Stated another way, functionalization is the separation and arrangement of costs according to major functions, such as production, transmission, and distribution.

Fixed costs are those costs which tend to remain constant over the short run irrespective of changes in output and are generally considered to be demand-related. Fixed costs include those costs which are a function of the size of the investment in utility facilities, and those costs necessary to keep the facilities “on-line.” Variable costs, on the other hand, are those costs which tend to vary with output and are generally considered to be commodity-related. Customer-related costs are those which are closely related to the number of customers served, rather than the quantity of energy consumed or the peak demands placed upon the system. An understanding of these concepts is essential to development of ECOS studies, as well as appropriate rate design.

<u>Review of PacifiCorp's Cost of Service Study</u>

Q. HAVE YOU REVIEWED THE COMPANY'S ECOS STUDY?

A. Yes. I have reviewed the Company's ECOS study that was submitted as part of PacifiCorp witness Joelle R. Steward's direct testimony in this case.[1/]

Q. IS THE COMPANY'S ECOS STUDY REASONABLE TO USE AS A BASIS FOR REVENUE ALLOCATION AND RATE DESIGN IN THIS CASE?

A. Not entirely. The ECOS study filed in this case is, in many respects, consistent with studies filed by PacifiCorp in the past and is reasonable in certain ways. However, I have serious concerns with two aspects of its study. First, the study classifies production plant investment to the customer classes using a method that is based only in small part (43%) on the customers' contribution to peak demand for each month of the year and in much larger part (57%) on the basis of energy.[2/]

This method is improper because the allocated plant investments include the cost of all production resources, and are dependent on the maximum capacities of those resources. Instead, production costs should be classified and allocated to the customer classes according to each class's demand during the peak months, when <u>all</u> of PacifiCorp's production resources are in use, and when those resources are most likely to be operating at their maximum capacities. It is PacifiCorp's system peak demands, which occur during winter and summer months, that drive the need for additional capacity. Demands during moderate-load times, whether time of day or month of year, do not cause new generating capacity to be built. Energy allocators

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1/ Exh. No. ___(JRS-1T).

2/ <u>Id.</u> at 6.

should be used only on variable costs, i.e., those which vary with the operating output of the units, such as fuel.

Second, in addition to its misclassification and misallocation of production costs, the Company's ECOS study also improperly classifies and allocates the costs of transmission.

<u>Classification and Allocation of Production-Related Costs</u>

Q. HOW HAS THE COMPANY CLASSIFIED AND ALLOCATED PRODUCTION-RELATED COSTS?

A. The Company's process is described and discussed at pages 5-11 of PacifiCorp witness Steward's direct testimony.

As described, PacifiCorp proposes to use the "Peak Credit" or "load factor" ratio to classify production and transmission resources. According to Ms. Steward, PacifiCorp utilizes the west control area system diversified load factor to determine the proportion of the production function that is demand-related. This modification yields a 43% portion to be allocated on the basis of demand, with the remaining 57% to be allocated on the basis of energy delivered. PacifiCorp performs this classification for both production fixed and variable costs and, as described below, to transmission plant. For the approximately 43% of costs that are classified as demand-related, PacifiCorp proposes to allocate on the Company's highest 100 summer and 100 winter hourly peak loads in the west control area for the year.

Q. SETTING ASIDE THE VALIDITY OF CLASSIFICATION USING THE PEAK CREDIT OR LOAD FACTOR METHOD FOR THE MOMENT, WHY HAS PACIFICORP USED THE HIGHEST 200 HOURS (100 SUMMER/100 WINTER) METHOD TO ALLOCATE THE PRODUCTION COSTS IN ITS ECOS STUDY?

A. PacifiCorp witness Steward states as follows:

> Consistent with the Commission's accepted practice in Washington, the demand-related portion continues to be allocated using class loads coincident with the Company's highest 100 summer (April-October) and highest 100 winter (November-March) hourly retail peak loads in the west control area.[3/]

Ms. Steward provides no rationale for her approach beyond this.

Q. DO YOU FIND THIS EXPLANATION COMPELLING?

A. No, I do not. The Company should provide a justification for its allocation approach beyond just "consistent with the Commission's accepted practice." Although I have not attempted to review the complete history of the Commission's acceptance of this approach, I can state that it does not appear to be adopted in all cases for all Washington utilities and has not always been used for PacifiCorp. For example, I participated in the recent rate case of Avista Corporation, Docket Nos. UE-140188 and UG-140189 (*consolidated*), and in that case no party advocated a top 100 summer peak hours/top 100 winter peak hours allocation approach.

Q. IS THERE SUPPORT FOR USE OF MULTIPLE PEAK HOURS FOR ALLOCATING PRODUCTION FIXED COSTS IN INDUSTRY LITERATURE?

A. There is some precedent for an approach that looks at multiple peak hours in determining production cost allocation. For example, in the NARUC Manual, one of the approaches for allocation of production fixed costs is the "multiple coincident peak method," which is described at page 46 of that document. Under that approach, criteria for determining which hours to use include (i) all hours of the year with demands within 5% or 10% of the system's peak demand; and (ii) all hours of the year in which a specified reliability index (loss of load probability, loss of load hours,

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3/ Id. at 6-7.

expected unserved energy, or reserved margin), passes an established threshold value.[4/] I do not see any evidence that PacifiCorp has set its proposed allocation based on any of these criteria. Therefore, it is without full support in the NARUC Manual.

Furthermore, I do not see any support in industry literature at all for use of this method of allocation of production costs when combined with a peak credit or load factor classification approach for production costs.

Q. WHY IS IT IMPORTANT TO CONSIDER ONLY THE HOURLY DEMANDS THAT ARE REASONABLY CLOSE TO THE SYSTEM PEAK?

A. By considering only the hourly demands that are reasonably close to the annual system peak, the cost analyst recognizes that it is only during the highest system load hours that production capacity is most likely to be fully utilized. Consequently, a demand allocation method that is based on each class's contribution during these high demand periods will fairly and reasonably recognize the classes' proportionate responsibility in causing the utility to incur those production investments.

Q. ARE THE TOP 100 SUMMER PEAK HOURS/ TOP 100 WINTER PEAK HOURS ALL CLOSE TO THE SYSTEM PEAK?

A. No. Some of the hours included in this allocation are as low as about 75% of the peak. Demands during hours that are 25% below the peak certainly do not cause a utility to incur additional production investments.

Q. DOES THE NARUC MANUAL PROVIDE ANY FURTHER USEFUL GUIDANCE AS TO AN APPROPRIATE PRODUCTION ALLOCATION METHOD FOR UTILITIES WITH DEMAND CHARACTERISTICS SIMILAR TO PACIFICORP'S?

A. Yes. Another instructive allocation method from the NARUC Manual is the "summer and winter peak method" which is used to "reflect the effect of two distinct seasonal

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4/ *NARUC Manual* at 46-47.

peaks on customer cost assignment."[5/] The NARUC Manual states: "If the summer and winter peaks are close in value, and if both significantly affect the utility's generation expansion planning, this approach may be appropriate."[6/]

As I will demonstrate below, during the test year and several recent years, PacifiCorp has exhibited the summer and winter peak conditions described above. Under the summer and winter peak method, either the single highest summer and single highest winter peaks are used (e.g., 2 CP) or a small number of summer and winter peak hours are used (e.g., 4 CP).

To summarize, if PacifiCorp had determined that the top 100 hours in summer and the top 100 hours in winter represented the top 5% or 10% of system peak load, then its approach may be supported by industry literature as a demand allocator. However, PacifiCorp has not done so and this is not the case.

Q. HAVE YOU DETERMINED HOW MANY HOURS OF THE PACIFICORP SYSTEM DEMAND FALL WITHIN 5% OF THE PEAK DEMAND?

A. Yes, I have, by reviewing the workpapers provided by Ms. Steward. Considering the total load in the west control area system, which is the basis for PacifiCorp's allocation, I determined that only four hours are within 5% of the system peak load, which occurred on December 9, 2013, at hour 8. All four of these hourly loads occurred in December, though on two different dates.

Similarly, I determined that in only 22 hours did the west control area system load fall within 10% of the peak. I would note that all 22 of these hours occurred in December 2013 as well, across several different dates.

[5/] Id. at 45.
[6/] Id.

Therefore, if a multiple coincident peak approach to allocation were to be used, it would be more appropriate to consider only the four highest hours or the 22 highest hours, given the criteria stated in the NARUC Manual.

Q. HAVE YOU DETERMINED DEMAND ALLOCATION FACTORS FOR THE CLASSES THAT WOULD RESULT IF THE TOP 5% OR TOP 10% OF HOURS WERE TO BE USED?

A. Yes, I have. Table 1, below, shows these allocation factors in comparison to PacifiCorp's 100 summer hours/100 winter hours allocation factors.

TABLE 1

Production Allocation Factor Comparison

Class	100 Summer Hrs / 100 Winter Hrs	Top 5% of Hours	Top 10% of Hours
Sch 16	43.0%	56.4%	57.0%
Sch 24	13.4%	10.7%	10.8%
Sch 36	21.4%	19.5%	18.3%
Sch 48T	8.7%	6.1%	6.0%
Sch 48T-D.F.	9.6%	7.1%	7.6%
Sch 40	3.5%	0.1%	0.1%
Lighting	0.2%	0.1%	0.2%
Total	100.0%	100.0%	100.0%

Q. IN LIGHT OF THIS, ARE YOU PROPOSING USE OF A TOP 4 HOUR OR TOP 22 HOUR DEMAND ALLOCATOR?

A. No. Although this approach would have stronger support in the NARUC Manual and would make a significant difference in the cost allocations, I am not recommending it at this time. Rather, I recommend that the multiple coincident peak hour be dropped altogether and that a more traditional and moderate approach utilizing monthly coincident peaks be adopted. For this purpose, I recommend that only customer loads during the highest monthly peak demands in the winter and summer be considered for allocating production investment.

Q. WHY ARE THE CUSTOMER LOADS DURING THE HIGHEST MONTHLY PEAK DEMANDS RELEVANT TO THE ALLOCATION OF PRODUCTION INVESTMENT?

A. The key factors that link customer loads at the time of the highest monthly peak demand to the allocation of production investment are the following:

1. Utilities typically bring all of their generating resources into operation in the hours leading up to their highest monthly peaks. This includes the base load, intermediate load and peaking plants, as well as the short-term and long-term power purchasing contracts. For many utilities in the United States, these peaks occur during the summer season. PacifiCorp exhibits peaks in both summer and winter, with the highest peak generally occurring in December.

2. The production costs that are allocated include the cost of base load, intermediate load and peaking plants, as well as the costs of short-term and long-term power purchase contracts.

3. The portion of the utility's highest monthly demand that is contributed by a customer class will provide a fair representation of the portion of production cost that the utility incurred to serve the class. For example, if a class constitutes 10% of the load at the times of system peak, it essentially represents 10% of the need for generation capacity and, thus, should be allocated 10% of production capacity costs.

Q. HAVE YOU HAD AN OPPORTUNITY TO REVIEW PACIFICORP'S HISTORICAL MONTHLY SYSTEM PEAK LOAD DATA?

A. Yes. These load data were obtained through data requests. Charts of the historical load data for the last six calendar years are shown on Exhibit ____(RRS-3). These charts indicate a dominant winter peak. Indeed, in only two years (2010 and 2012) is a summer peak within 10% of the winter peak, as shown by the red tips on the bars in the charts. In 2013, no other monthly peak demands were within 10% of the December peak.

Table 2, below, summarizes the number of months in each of the last six calendar years that were within 5% and 10% of the system peak, including the peak month itself.

TABLE 2

Number of Months In Which Peak Demands Were Near Annual Peak Demands (including Peak Month)

Year	Within 5% of Peak	Within 10% of Peak
2008	2	2
2009	1	1
2010	1	3
2011	2	3
2012	2	5
2013	1	1

As can be seen from Table 2, PacifiCorp has peak demands that are within 10% of the system peak in relatively few months each year, and even fewer are within 5% of the peak.

Applying the criteria from the NARUC Manual regarding the selection of multiple coincident peaks to the test year monthly peak data, a 1 CP allocation method would reflect the number of monthly peaks within 5% or 10% of the annual peak (inclusive). However, 2013 is somewhat anomalous as it actually had no other months within 5% or within 10% of the peak.[7/] Considering multiple years, as shown in Table 2, suggests that a 4 CP allocator, which is often supported for allocating fixed production costs, would be reasonable (if not conservative) in this case. Considering the years shown on Exhibit No.___(RRS-3), a normal 4 CP allocator would include January, July, August and December and, thus, would also match and equally

[7/] This last occurred in 2009, as shown in Table 2.

represent the summer and winter peaks exhibited by PacifiCorp's customers.[8/] This allocation method finds greater support in the NARUC Manual than does the methodology used by PacifiCorp, as discussed previously.

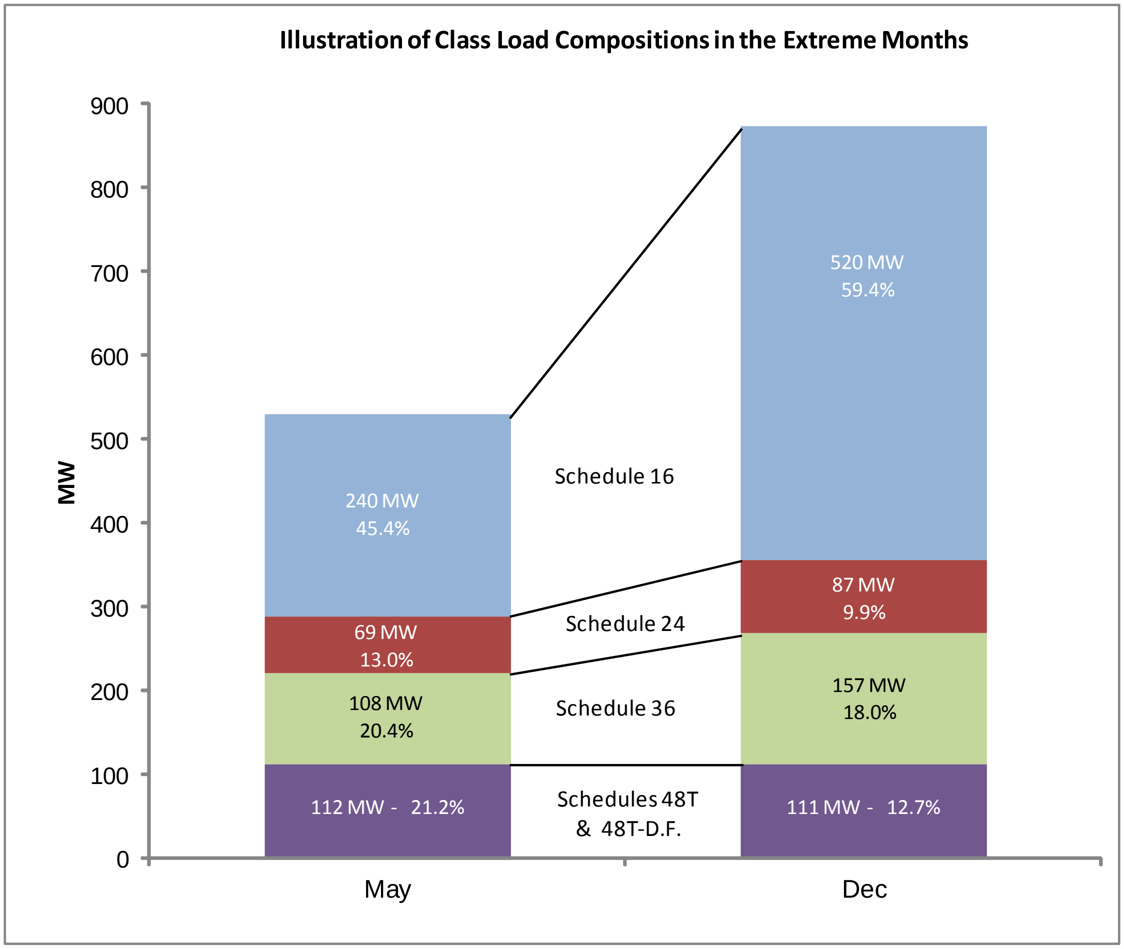
The Company's peak demands during the other months are significantly lower than those that occur during these summer and winter peak months.

Q. CAN YOU ILLUSTRATE THE DIFFERING CUSTOMER CLASS PROPORTIONS OF SYSTEM LOAD DURING PEAK MONTHS, AS OPPOSED TO NON-PEAK MONTHS?

A. Yes. Figure 1 below shows the major PacifiCorp customer schedules' contribution to peak load during the Company's extreme (i.e., highest and lowest), demand months of December and May, when its test year system loads are at the maximum and minimum, respectively.

[8/] Alternatively, November could be substituted for August, as those two months can fluctuate in and out of the top four from year to year.

Figure 1



Excludes Schedule 40 - Irrigation and Street Lighting schedules

As can be seen from Figure 1, peak loads of the Schedules 16, 24 and 36 customer classes are much higher in December than in May, undoubtedly due primarily to heating, while Schedule 48T is relatively unchanged/flat in December and May. It is these additional loads of the Schedules 16, 24 and 36 customers that drive the peak loads of PacifiCorp and the need for generating capacity.

Q. PLEASE COMMENT ON THE PEAK CREDIT OR LOAD FACTOR METHOD OF CLASSIFICATION OF PRODUCTION COSTS.

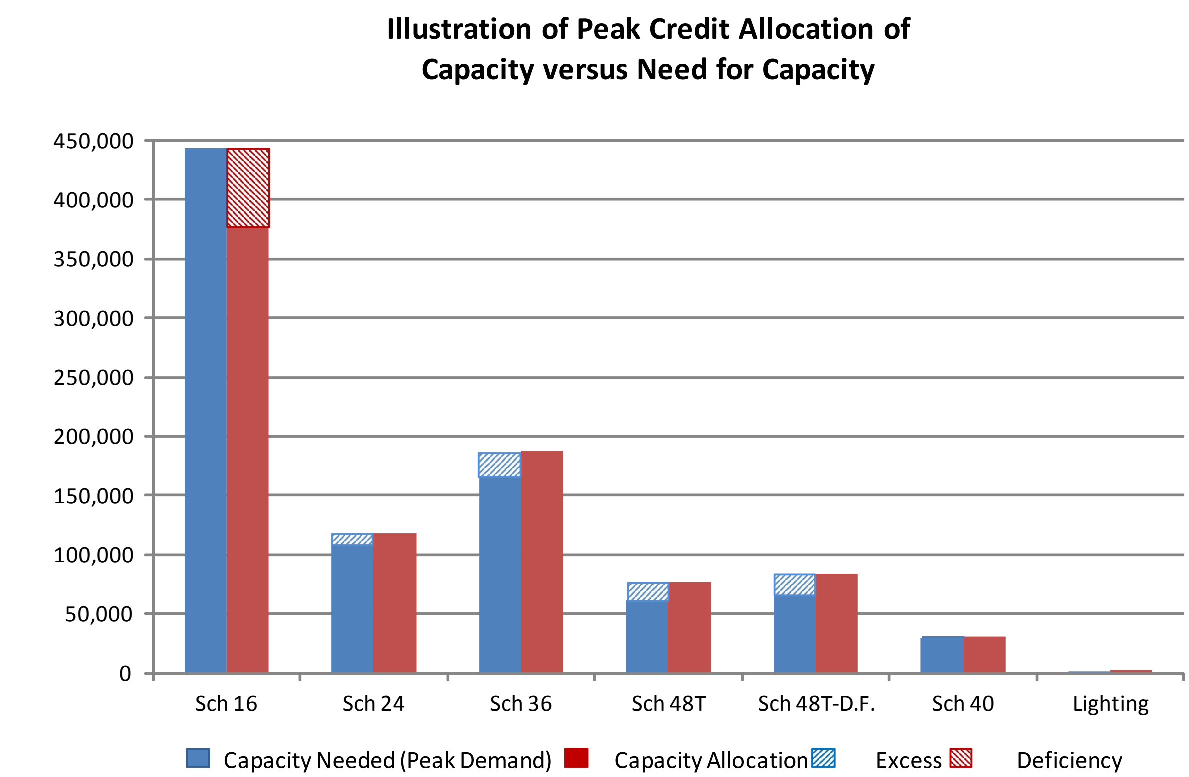
A. I do not agree with the Peak Credit or load factor method[9/] used to classify production costs between demand and energy components, as proposed by PacifiCorp. This approach is sometimes referred to as the "peak and average demand" method and is given little discussion in the NARUC Manual. While I do not have the complete history of its use in PacifiCorp cases, typically the use of this type of method for classification or allocation of production costs is based on a perceived trade-off between capacity investment and fuel savings. In my opinion, this classification inappropriately assigns far too much weight to energy usage as a basis for assigning production costs.

In considering how PacifiCorp classifies and allocates production plant, and considering the peak demands of the various rate schedules, it is clear that not enough production capacity is assigned to some of the rate schedules and too much is allocated to others. This is illustrated in Exhibit No. ____(RRS-4r), which shows the equivalent amount of capacity allocated to customer rate schedules, as compared to their peak demands.[10/] As shown in this exhibit, Schedules 48T and 48T-Dedicated Facilities are allocated considerably more capacity than their peak demands warrant, while Schedule 16, for example, is not assigned enough capacity to meet its peak capacity needs. Figure 2 below graphically depicts the results of Exhibit No.___(RRS-4r). This highlights a major weakness of the Peak Credit method.

9/ Although Ms. Steward uses both "Peak Credit" and "load factor" to reference this method in her testimony, no distinction appears to be made. I will refer to it simply as "Peak Credit" hereinafter.

10/ For peak demands, I have utilized the average of the 4 CP, as discussed above. Had I used the actual peak or the single CP, the results shown would have been more dramatic.

Figure 2



Q. WHAT CLASSIFICATION OR ALLOCATION METHODOLOGY DO YOU RECOMMEND FOR PRODUCTION INVESTMENT IN THIS CASE?

A. Because production investment is primarily due to the need for and the size of the peak demands of customers, it should be assigned to customer classes exclusively, or at least primarily, on those classes' contribution to utility system peaks. Allocation by this method has widespread support in the industry and is, in my view, a better reflection of cost causation than allocation methods that utilize energy usage to any significant degree. Furthermore, even when energy usage (as measured by average demand) is utilized, a far more appropriate and typical approach is the "average and excess demand" method.[11] Thus, I propose that 100% of production fixed costs be classified as demand related, and variable costs be classified as energy related.

Q. TO YOUR KNOWLEDGE, IS THE COMMISSION CONSTRAINED TO ADOPT A PEAK CREDIT APPROACH FOR CLASSIFYING PRODUCTION COSTS FOR PACIFICORP IN THIS CASE?

A. It appears that the Peak Credit method has been used for PacifiCorp for some time. However, I am not aware that the Commission has precluded itself from considering other approaches in the future, as circumstances change and theories evolve. In fact, the Commission stated as much in a 1993 Order in Docket Nos. UE-920433 *et al.*, related to Puget Sound Energy, Inc. ("Puget" or "PSE"). Specifically, in discussing the reasonability of the Peak Credit method, the Commission stated:

> The Commission does not, however, accept the Company's invitation to designate Puget's model to be used as the standard in future proceedings. As circumstances change, and theories evolve, other approaches to cost of service analysis may prove to be relevant.[12]

Assuming the Commission is not constrained to utilize the Peak Credit method due to its prior use, I recommend it not be used in this case. On the other hand, if the Commission is constrained to utilize the peak credit method, I recommend that it be refined in its application.

Q. IF THE PEAK CREDIT CLASSIFICATION IS ADOPTED, HOW WOULD YOU RECOMMEND THAT THE APPROACH BE REFINED?

A. In that case, the heavy reliance on energy usage in assigning costs (57%) highlights the critical need to refine the demand allocator used for capacity costs. As mentioned, the PacifiCorp electric system exhibits a predominant winter peak and a summer peak.

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[11] See *NARUC Manual* at 49-52.

[12] WUTC v. PSE, Docket Nos. UE-920433 *et al.*, 9th Suppl. Order at 8 n.5 (August 17, 1993).

Therefore, any method of cost allocation that considers loads in hours that do not contribute to the need for new generation, or any energy-based method,[13/] does not adequately account for the dominant seasonal system peaks, fails to reflect the actual load characteristics of the PacifiCorp system, and fails to properly reflect class responsibility for production investment. Thus, for PacifiCorp, a 2 CP, 3 CP or 4 CP allocation would be more appropriate for demand-related production costs. This is true in the context of a full allocation of production investment, or as used in conjunction with the Peak Credit classification approach.

To be conservative, I recommend the use of 4 CP in this case. Specifically, I recommend that the two highest summer and two highest winter months be used, giving recognition to both seasons (as does PacifiCorp's 100 summer hours/100 winter hours allocation). The months chosen are July and August for summer and January and December for winter. As mentioned previously, these months are typically the highest for PacifiCorp.

Q. HAVE YOU CALCULATED THE 4 CP ALLOCATION FACTORS NECESSARY TO APPROPRIATELY ALLOCATE DEMAND-RELATED PRODUCTION COSTS IN PACIFICORP'S ECOS STUDY?

A. Yes. These allocation factors, along with PacifiCorp's proposed 100 summer/100 winter allocation factors, are shown in Table 3, for each of the PacifiCorp rate schedules in the ECOS study, and allow for ready comparison across the allocation methods.

[13/] Similarly, allocating costs on average demand is mathematically equivalent to a kWh allocation and ignores the distinctions between peak period usage and off-peak period usage.

TABLE 3

Production Allocation Factor Comparison

Class	100 Summer Hrs / 100 Winter Hrs	4CP
Sch 16	43.0%	50.6%
Sch 24	13.4%	12.4%
Sch 36	21.4%	19.1%
Sch 48T	8.7%	7.0%
Sch 48T-D.F.	9.6%	7.6%
Sch 40	3.5%	3.3%
Lighting	0.2%	0.1%
Total	100.0%	100.0%

Q. HAVE YOU MODIFIED THE PACIFICORP ECOS STUDY SO THAT PRODUCTION-RELATED COSTS ARE ALLOCATED USING YOUR RECOMMENDED 4 CP RATHER THAN THE 100 SUMMER/100 WINTER METHOD?

A. Yes. I have calculated the ECOS study for the recommended 4 CP demand allocation method under both a 100% demand allocation of production capacity costs, and in the context of PacifiCorp's Peak Credit classification (43% demand, 57% energy). For the 100% demand 4 CP allocation, I calculate the ECOS results if the peak credit method for classification is not used at all and, instead, production fixed costs are allocated on the basis of 4 CP demand alone. Disuse of the Peak Credit method altogether will require some modifications to the allocation of production variable costs and transmission costs. I have used a 100% energy allocator for variable production costs,[14/] and a 100% 12 CP allocator for transmission costs. This treatment of transmission costs will be discussed further in the next section. The results of this

[14/] The FERC accounts that I have considered variable production are 501, 501NPC, 503, 518, 547NPC and 555 (in part).

allocation method are shown in Exhibit No. ____(RRS-5r).[15/] This is my recommended ECOS approach. For some rate schedules, the change in production cost allocator makes a significant difference in the cost of service, as compared to the Company's results.

I have also modified the PacifiCorp ECOS study to adopt a 4 CP demand measure, within the context of the Peak Credit classification approach, should the Commission adopt the Peak Credit method. For this version of the ECOS study, no other changes were made as compared to PacifiCorp's proposed study. The results of this modification are shown in Exhibit No. ___(RRS-6r). As with my primary recalculation shown in Exhibit No. ___(RRS-5r), the change in the demand measure makes a significant difference in the schedules' overall cost of service.

Q. DOES YOUR RECOMMENDATION FOR A 4 CP DEMAND ALLOCATOR ALIGN WITH COMMISSION STANDARDS?

A. Yes, based on my reading of prior Commission orders, including standards given in the context of PacifiCorp's allocation methodology. I will offer my understanding of the Commission's standards for the purpose of explaining why I believe my 4 CP proposal aligns with Commission guidance.

In the 1993 case mentioned earlier, the Commission accepted a similar top 200 hour proposal from another electric utility, Puget, which the Commission found to be "reasonably representative of the system peak and the actual resources put into place to serve that peak."[16/] The Commission did not state that using the top 200 hours was the only "reasonably representative" demand allocator. Also, PacifiCorp had

[15/] Exhibit Nos.___(RRS-5r, 6r and 8r) utilize the same two-page summary format as used by Ms. Steward in Exhibit No.___(JRS-4) at Tab 4.0 – Pages 1 and 2, showing results at current return (p. 1) and target return (p. 2).

[16/] Docket Nos. UE-920433 *et al.*, 9th Suppl. Order at 12.

employed a 12 CP allocator *before* switching to 200 hour method.[17/] Regardless of the specific allocator used, however, I understand the Commission's standard as follows: "Generally, the proper period over which to allocate the demand-related costs of peaking resources is the hours when they are expected to be used."[18/]

In the Company's 2010 general rate case, my understanding is that the Commission reaffirmed and further added to this standard when it stated: "While it is reasonable to allocate the costs of peaking resources based on the hours those resources will actually be used to serve load, the allocation method should be flexible enough to incorporate the variable peaks experienced in Washington."[19/] Accordingly, my proposed 4 CP demand allocator is designed to capture the Company's actual peak resource hours while retaining flexibility to incorporate variability.

Q. PLEASE EXPLAIN.

A. First, I believe that the 4 CP method better captures the Company actual peak resource hours than does the top 100 summer/top 100 winter approach used by PacifiCorp for the reasons previously explained. The use of these 200 hours is simply too broad of a determination and includes many hours that are well below the system peak times, when resources are strained. As mentioned, the PacifiCorp method includes some hours where the demand is as low as 75% of the peak. Clearly, such hours are not a fair representation of times when the system capacity is expected to be strained.

Second, my 4 CP allocation approach is flexible enough to incorporate the variable peaks experienced in Washington because it looks at the peak demands in

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17/ Compare WUTC v. PacifiCorp, Docket No. UE-991832, Taylor, Exh. No.___(DLT-T) at 5, with WUTC v. PacifiCorp, Docket No. UE-032065, Taylor, Exh. No.___(DLT-1T) at 29-30.

18/ Docket Nos. UE-920433 *et al.*, 9th Suppl. Order at 12.

19/ WUTC v. PacifiCorp, Docket No. UE-100749, Order 06 at ¶ 304 (Mar. 25, 2011).

different months within seasons. My approach gives equal weighting to the December and January peaks, for example, while PacifiCorp's approach gives December hours over 80% of the weighting, since 82 of the top 100 winter hours are in December.

Q. ARE THERE OTHER METHODOLOGIES TO CONSIDER HERE?

A. Potentially, other parties may recommend a new look at the methodologies used in allocating costs among customer classes. I will review those and comment in the cross-answering testimony, as appropriate.

Q. SHOULD THE COMMISSION RETAIN THE PEAK CREDIT METHOD FOR CLASSIFYING PRODUCTION COSTS, IS EXHIBIT ____(RRS-6r) YOUR RECOMMENDED ECOS STUDY RESULT?

A. No. Although this is the most similar to the PacifiCorp ECOS study, I do not recommend that transmission costs be classified according to the Peak Credit method under any circumstance, as I will discuss below.

Classification and Allocation of Transmission Costs

Q. HOW DOES PACIFICORP CLASSIFY TRANSMISSION COSTS IN ITS ECOS STUDY?

A. It uses the same Peak Credit methodology as is used for classifying production costs.

Q. WHAT IS THE COMPANY'S RATIONALE FOR CLASSIFYING TRANSMISSION COSTS IN THIS MANNER?

A. Company witness Steward's direct testimony in this case does not distinguish between production and transmission in this regard. Even if classification of generation in this way were warranted, which is not the case, this still would not justify classification or allocation of transmission costs in this unusual manner.

Q. WHY DO YOU BELIEVE THIS CLASSIFICATION AND ALLOCATION METHOD IS UNUSUAL?

A. I am not aware of any case outside of Washington and not involving PacifiCorp where a utility has classified or allocated transmission plant costs on the basis of energy to *any* degree. I see no justification for allocating transmission costs in this manner.

Q. WHY DO YOU BELIEVE THERE IS NO JUSTIFICATION FOR UTILIZING AN ENERGY COMPONENT IN CLASSIFYING OR ALLOCATING TRANSMISSION PLANT COSTS?

A. Unlike production, where parties sometimes claim there is a trade-off between fixed and variable costs that justify an energy component in the allocation to reflect cost-causation, there is not even an arguable trade-off for transmission facilities.

I can illustrate this through a simple hypothetical. If a utility were to build a 1,000 Megawatt ("MW") generating unit in an area that is not adjacent to transmission facilities, additional transmission facilities would need to be constructed to connect the generating unit to the electrical grid. The capacity of the new transmission facilities would need to be designed to carry the maximum output of the generating unit. The capacity of those new transmission facilities is not dependent on the fuel type or economics of the generating unit being constructed or how often it is run. Said another way, essentially the same transmission facilities would need to be built whether the 1,000 MW unit is a nuclear power plant, with a very high capacity factor producing 7.9 million MW hours per year ("MWh/year"), or a natural gas-fired peaking plant with a much lower capacity factor producing 4.4 million MWh/year. The transmission facilities would be designed and constructed to meet the maximum capacity (1,000 MW) required over the lines.

Similarly, increased or decreased utilization of the transmission system, once it is built, does not impact the costs of the transmission assets. For example, higher cumulative energy flow without an increase in demand does not impact transmission costs. Transmission costs are virtually all fixed, not variable with energy flow. For these reasons, an energy classification or allocation of transmission costs simply is not justified.

Q. HAS THE COMPANY CONFIRMED THAT ITS TRANSMISSION SYSTEM IS CONSTRUCTED TO MEET THE PEAK DEMAND OF ITS CUSTOMERS?

A. Yes. My review of PacifiCorp's transmission planning information refers to use of demand levels, but reveals no reliance on energy flow as a planning criterion. For example, PacifiCorp's Local Transmission Planning Practices Document, referenced in Attachment K of its Open Access Transmission Tariff ("OATT"), makes multiple references to forecasting *demand* for planning purposes, but makes no reference to energy in this regard.

Q. ARE THERE OTHER REASONS FOR NOT UTILIZING THE PEAK CREDIT METHOD FOR ALLOCATING TRANSMISSION COSTS?

A. Yes, there are. In providing guidance to utilities in billing for network transmission service, the Federal Energy Regulatory Commission ("FERC") utilizes 12 CP, without regard to the amount of energy flowing across the lines over time.[20] Further, in billing for transmission service, PacifiCorp itself utilizes a 12 CP billing method for network transmission service as specified in Sections 34.1 and 34.2 of PacifiCorp's OATT. A copy of Section 34 of that tariff is attached as Exhibit No. ___(RRS-7).

[20] Generally, FERC Orders 888 and 889 dealt with these matters.

Q. BESIDES 12 CP, ARE THERE ANY OTHER REASONABLE OPTIONS FOR ALLOCATION OF TRANSMISSION COSTS?

A. Yes, considering that the transmission system is built to meet the peak demands on the system (as opposed to times of relatively low demands), it would not be unreasonable to use a 1, 2, 3 CP or 4 CP measure for allocating transmission costs, given PacifiCorp's annual load shape showing some monthly peak demands to be well below the annual peak. Indeed, some Regional Transmission Organizations effectively use a 1 CP or 5 CP for billing for transmission service. However, although 12 CP may not be the truest measure of transmission cost-causation, as it overemphasizes demands in non-peak seasons, given its widespread use by other utilities around the country and by FERC, it is reasonable (though conservative) for use in this case.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that transmission system costs not be classified as energy related under the Peak Credit method. Moreover, the 12 CP demand measure should be used for 100% allocation of transmission costs.

Q. CAN YOU PROVIDE A COMPARISON OF THE TRANSMISSION ALLOCATION FACTORS THAT YOU RECOMMEND TO THOSE USED BY PACIFICORP?

A. Yes, I can. The resulting effective transmission allocation factors are shown in Table 4.

TABLE 4

Transmission Allocation Factor Comparison

Class	PacifiCorp Allocation	12CP Allocation
Sch 16	43.0%	47.4%
Sch 24	13.4%	12.1%
Sch 36	21.4%	21.0%
Sch 48T	8.7%	8.0%
Sch 48T-D.F.	9.6%	8.2%
Sch 40	3.5%	3.3%
Lighting	0.2%	0.1%
Total	100.0%	100.0%

Q. CAN YOU PROVIDE THE RESULTS OF APPLYING THE 12 CP ALLOCATION OF TRANSMISSION COSTS TO THE MODIFIED PEAK CREDIT ALLOCATION OF PRODUCTION COSTS?

A. Yes. This information is provided in Exhibit ____(RRS-8r). This exhibit differs from Exhibit No. ____(RRS-6r) only in that transmission costs are 100% classified and allocated on 12 CP. If the Peak Credit is retained at all, it should only be retained for production costs and the results in Exhibit No.___(RRS-8r) should be used.

<u>Overall Cost of Service Results</u>

Q. CAN YOU PLEASE PROVIDE A SUMMARY OF THE RESULTS OF THE ECOS STUDIES MODIFIED FOR BOTH OF YOUR RECOMMENDATIONS FOR PRODUCTION COST ALLOCATION AS WELL AS TRANSMISSION COST ALLOCATION?

A. Yes. This information is provided in Table 5, below, which provides the rate schedule returns under PacifiCorp's ECOS study, my preferred ECOS study, Exhibit No. ____(RRS-5r) and the modified Peak Credit (production-only) ECOS study, Exhibit No. ____(RRS-8r).

TABLE 5

Summary Comparison of Cost of Service Study Results

Schedule	PacifiCorp ECOS Study Rate of Return	PacifiCorp ECOS Study Index	Exhibit No.___(RRS-5r) Recommended ECOS Study Rate of Return	Exhibit No.___(RRS-5r) Recommended ECOS Study Index	Exhibit No.___(RRS-8r) Modified Peak Credit ECOS Study Rate of Return	Exhibit No.___(RRS-8r) Modified Peak Credit ECOS Study Index
Schedule 16	3.55%	0.61	1.55%	0.27	2.45%	0.42
Schedule 24	10.17%	1.76	12.32%	2.13	11.64%	2.01
Schedule 36	7.56%	1.31	9.44%	1.63	8.33%	1.44
Schedule 48T	6.62%	1.15	10.39%	1.80	8.02%	1.39
Schedule 48T-D.F.	4.16%	0.72	8.78%	1.52	5.83%	1.01
Schedule 40	9.32%	1.61	10.29%	1.78	9.58%	1.66
Schs. 15,52,54,57	9.85%	1.70	16.07%	2.78	12.29%	2.13
Total	5.78%	1.00	5.78%	1.00	5.78%	1.00

Notes:

	PacifiCorp ECOS Study	Exhibit No.___(RRS-5r)	Exhibit No.___(RRS-8r)
Production (fixed)	Top 100S/100W 43%D/57%E	4 CP 100% D / 0% E	4 CP 43% D / 57% E
Production (variable)	Top 100S/100W 43%D/57%E	100% Energy	4 CP 43% D / 57% E
Transmission	Top 100S/100W 43%D/57%E	12 CP 100%	12 CP 100%

As Table 5 shows, the cost returns vary significantly from PacifiCorp's calculation. For example, rather than a rate of return index of 0.72 for Schedule 48T-Dedicated Facilities, under my adjusted measure of cost of service, the rate of return index is 1.52, meaning that Schedule 48T-Dedicated Facilities customers actually are providing revenues to produce a return higher than the system average, i.e., indicating that this class is currently providing revenues above test year cost of service.

III. ELECTRIC REVENUE ALLOCATION ("RATE SPREAD")

Q. PLEASE DISTINGUISH THE REVENUE ALLOCATION STEP IN THE PROCESS FROM THE COST OF SERVICE ANALYSIS.

A. As previously mentioned, the cost of service analysis is an empirical analysis of the costs caused by the various customer schedules. In itself, it does nothing to change customers' rates. Rather, determining how much of the revenue requirement should be borne by each rate schedule is the step known as revenue allocation or rate spread.

The rate spread should be based on the results of the cost of service study, since cost-based rates tend to be the most economically efficient. However, the rate spread can be influenced by other principles, such as rate continuity, rate moderation and avoidance of rate shock.

Q. WHAT IS PACIFICORP'S PROPOSAL REGARDING RATE SPREAD?

A. As explained by Company witness Steward, PacifiCorp proposes a two tiered rate spread approach, as shown on Table 3, page 14 of Ms. Steward's testimony. Ms. Steward explains the proposal as follows:

> The Company proposes a rate spread that allocates the revenue requirement change to rate schedule classes guided by the results of the cost of service study. Specifically, the Company proposes to: (1) allocate an increase based on one-half of the overall increase—or 4.2 percent—to the schedules that the cost of service study indicates require a significantly smaller revenue increase (Schedules 24, 40, and lighting schedules); (2) the remaining increase is then spread equally to the rest of the rate schedules, which results in a 9.5 percent increase.[21/]

Ms. Steward claims that the proposed rate spread minimizes price impacts on customers while fairly reflecting cost of service.

Q. IS PACIFICORP'S PROPOSAL REASONABLE?

A. Yes, in part, as I will explain. It is clear from her statement that Ms. Steward's proposal is based on the results of PacifiCorp's ECOS study showing that certain classes, to varying degrees, are currently over-paying or under-paying, as evidenced by the "% of COS" measure, as shown on Table 3 of Ms. Steward's direct testimony.

Ms. Steward's proposal effectively caps the increase at 12% above the system average increase. According to the Company's response to Boise Data Request 11.3, if the allowed increase is below PacifiCorp's request of 8.5%, then the rate spread

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21/ Exh. No. ___(JRS-1T) at 13-14.

recommendation would be adjusted proportionally, unless there is no increase, in which case PacifiCorp would recommend no rate change. This suggests that this 12% above system average cap would apply regardless of the ultimate recommended increase. For example, if the approved PacifiCorp increase were to be 5.0%, then the cap on the classes' increase would be approximately 5.6% (5.0 x 1.12). For the class that is currently paying the farthest below cost of service, Schedule 16-Residential, there would still be a significant under-recovery compared to cost of service at the maximum level of increase. This is true under both PacifiCorp's measure of cost of service and especially at my recommended measure of cost of service, as shown on Table 5 above.

In addition, PacifiCorp's recommended approach can lead to anomalous results because of the step-change nature of the tiers. Whether a customer schedule gets a 4.2% increase or a 9.5% increase under Ms. Steward's recommendation depends only on whether the customer schedule is above or below the hard trigger of 100% of cost of service, irrespective of the level of deviation. To illustrate the anomaly, consider the extreme case of two separate rate schedules, both of which are providing revenues at almost exactly the cost of service. The first rate schedule is slightly above cost of service at 100.01%. This schedule would receive a 4.2% increase under PacifiCorp's approach. The second hypothetical rate schedule is just under 100.0%, at 99.99% of cost of service, and would receive a 9.5% increase under PacifiCorp's approach. Thus, although these two rate schedules are almost identically situated in terms of meeting cost of service, they would receive much different revenue allocations under the PacifiCorp approach.

Although I can accept the Company's proposal to cap the increase at no more than 12% higher than the system average increase, I recommend that movement toward cost of service be made to the maximum extent possible within this constraint. This would mean that schedules currently paying above cost of service would get a lower increase, or possibly a decrease, commensurate with their revenue/cost situation. The actual impact, of course, will depend on which measure of cost of service is adopted and the ultimate approved revenues.

Q. WHAT DO YOU RECOMMEND FOR RATE SPREAD?

A. Formalizing what I indicated above, my recommendation for rate spread is the following. Movement toward cost of service should be made to the maximum extent possible, subject to the following constraint. No rate schedule should receive an increase greater than 1.12 times the system average increase. This will provide a measure of rate moderation and avoidance of rate shock. However, if the average increase granted by the Commission is very low, i.e., less than 2%, then a floor on the maximum increase should be set at 2%. This is because a 2% increase could be considered moderate and normally would not be considered to constitute rate shock.

By eliminating the two tier approach and substituting a revenue cap approach (based on PacifiCorp's upper tier), I have eliminated the possibility of the anomalous results described in my previous answer. This is because the two hypothetical rate schedules described in my hypothetical scenario would receive nearly identical rate increases, which is a more equitable situation.

To the extent that the increase to a rate schedule is "maxed out" at the ultimate rate cap described above, then any additional revenues that would be needed to reflect cost of service from that schedule would need to be reassigned to other schedules, in proportion to the class cost of service. Care should be taken to ensure that this reassignment of revenues to other schedules does not cause any of those schedules to exceed the described cap. If this is the case, then an additional iteration of revenue reassignment will be needed, until the increases to all schedules are within the rate cap.

Q. WHAT WOULD BE THE IMPLICATION OF YOUR PROPOSAL, AS COMPARED TO PACIFICORP'S APPROACH?

A. Although the full rate spread analysis cannot be known until the Commission has determined the overall revenue increase allowed, I have illustrated the results of my approach in Table 6 below, using also PacifiCorp's proposed increase and ECOS study results. As shown in Table 6, below, the impact would modify slightly the approach taken by PacifiCorp, as shown in Table 3 of Ms. Steward's direct testimony, at page 14 and reproduced in my table. In column E of her table, the schedules that would receive a 9.5% increase under PacifiCorp's proposal would still receive a 9.5% increase under my proposal. However, under my recommended approach, the percentage increase to the schedules that are designed to receive a 4.2% increase would have different percentages, since their percent of cost of service (shown in column D) is different. As alluded above, the impact of my proposal may be greater than what is illustrated in Table 6, if the Commission approves a different ECOS study or revenue increase for PacifiCorp.

A	B	C	D	E	F	G	H
TABLE 6							
Illustration of Proposed Rate Spread							
Schedule No.	Description	**Cost of Service Study** % Change	% of COS	**PacifiCorp Proposed** %	($000)	**Boise Proposed** %	($000)
16	Residential	15.5%	86.6%	9.5%	13,316	9.5%	13,309
24	Small General Service	-2.8%	102.9%	4.2%	2,053	3.9%	1,868
36	Large General Service < 1,000 kW	3.6%	96.5%	9.5%	6,350	9.5%	6,347
48T	Large General Service > 1,000 kW	6.0%	94.3%	9.5%	2,503	9.5%	2,474
48T	Large General Service Dedicated Facilities	12.4%	89.0%	9.5%	2,371	9.5%	2,369
40	Agricultural Pumping Service	-0.8%	100.9%	4.2%	537	6.0%	757
15,52,54,57	Street Lighting	-2.1%	102.2%	4.2%	70	4.6%	76
	Total Washington Jurisdiction	8.5%	100.0%	8.5%	27,200	8.5%	27,200

Q. DOES THIS CONCLUDE YOUR RESPONSIVE TESTIMONY?

A. Yes, it does.