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. 13-035-184**
In the Matter of the Application of Rocky Mountain Power for Approval of Revisions to Back-Up, Maintenance, and Supplementary Power Service Tariff, Electric Service Schedule 31	**Docket No. 13-035-196**

Direct Testimony and Exhibits of

Maurice Brubaker

on Cost of Service and Schedule 31

On behalf of

The Utah Industrial Energy Consumers

May 22, 2014

BRUBAKER & ASSOCIATES, INC.

Project 9868|9862

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. 13-035-184**
In the Matter of the Application of Rocky Mountain Power for Approval of Revisions to Back-Up, Maintenance, and Supplementary Power Service Tariff, Electric Service Schedule 31	)	**Docket No. 13-035-196**

STATE OF MISSOURI)
) SS
COUNTY OF ST. LOUIS)

Affidavit of Maurice Brubaker

Maurice Brubaker, being first duly sworn, on his oath states:

1. My name is Maurice Brubaker. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Utah Industrial Energy Consumers in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and exhibits which were prepared in written form for introduction into evidence in the Public Service Commission of Utah, Docket Nos. 13-035-184 and 13-035-196.

3. I hereby swear and affirm that the testimony and exhibits are true and correct and that they show the matters and things that they purport to show.

____
Maurice Brubaker

Subscribed and sworn to before me this 21st day of May, 2014.

____
Notary Public

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. 13-035-184**
In the Matter of the Application of Rocky Mountain Power for Approval of Revisions to Back-Up, Maintenance, and Supplementary Power Service Tariff, Electric Service Schedule 31	**Docket No. 13-035-196**

Table of Contents to the
Direct Testimony of Maurice Brubaker

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. 13-035-184**
In the Matter of the Application of Rocky Mountain Power for Approval of Revisions to Back-Up, Maintenance, and Supplementary Power Service Tariff, Electric Service Schedule 31	**Docket No. 13-035-196**

<u>Direct Testimony of Maurice Brubaker</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. 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 President of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

INTRODUCTION AND SUMMARY

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Utah Industrial Energy Consumers ("UIEC") intervention group. The UIEC customers purchase substantial quantities of electricity from Rocky Mountain Power Company ("RMP") in Utah, and are vitally interested in the outcome of this proceeding.

Q WHAT IS THE SUBJECT OF YOUR DIRECT TESTIMONY?

A My testimony addresses class cost of service, revenue allocation and rate design issues.

Q WHAT IS THE RELATIONSHIP OF YOUR TESTIMONY TO THAT OF DR. JONATHAN LESSER, WHO ALSO ADDRESSES COST OF SERVICE AND OTHER ISSUES FOR UIEC?

A Dr. Lesser provides an overview of the economic and costing principles that are the foundation for an appropriate allocation of RMP's Utah jurisdictional costs to its various classes of customers.

I present important jurisdictional and class load data which clearly identifies the nature of the changes that have occurred in the PacifiCorp and Utah customer load shapes. I also analyze customer class load shapes.

Building upon this information, and Dr. Lesser's analyses, I then discuss several different class cost of service allocation methods that better reflect cost-causation by Utah customers.

In addition, I present a design for standby Schedule 31 based on RMP's embedded cost generation retail revenue requirements, while Dr. Lesser presents an alternative to Schedule 31 that includes a market-based supply component.

Q WHAT IS THE CENTRAL POINT OF THE UIEC POSITION IN THE RATE CASE?

A The central point is that although the 12CP-75% demand / 25% energy allocation method may be acceptable at the jurisdictional level as a compromise for the purpose of providing RMP with an opportunity to recover all of its costs; the methodology is not based on cost-causation and is inappropriate at the state level for allocating costs among diverse customer classes. Cost-causation principles require that fixed costs of the generation system be allocated to customer classes based on their demands at times that are critical for the system – namely, the summer peaks. The 12CP approach does not reflect that. Also, the 25% weighting of energy in the development of the allocation factor dilutes the demand-based price signal and is at odds with cost-causation principles.

Furthermore, the 12CP-75%/25% methodology is adverse to high load factor and off-peak users of electricity. Both the 12CP allocation and the 75%/25% weighting over-allocate costs to these high load factor customers and to off-peak customers. The practical effect also is to dilute the price signal delivered to customers who use power disproportionately during the summer. It reduces their incentive to control the peak demands which cause RMP to build additional system capacity.

Both from a cost-causation point of view and from a fairness and equity point of view, the 12CP-75%/25% method is not just and reasonable and should be abandoned at the class level and instead an allocation based on the four summer monthly peak loads ("4CP") should be adopted.

Another central theme is related to the energy balancing account ("EBA"). The information presented herein demonstrates that there are substantial variations from month-to-month in the variable cost component of net power costs ("NPC"). These variations should be recognized in the class cost of service studies.

In addition, a cost-based standby rate should be available to customers who want to take this service. Two options should be available to the customer. They are: (1) a rate based on Utah PSC embedded cost generation revenue requirements; and (2) a rate that includes a market-based supply component.

Q PLEASE SUMMARIZE YOUR SPECIFIC FINDINGS AND RECOMMENDATIONS?

A My specific findings and recommendations may be summarized as follows:

<u>Docket No. 13-035-184:</u>

1. Both the PacifiCorp system and the Utah jurisdiction have a predominant summer peaking characteristic, which supports a summer coincident peak allocation for generation and transmission fixed costs, and not RMP's 12CP-75%/25% allocation [see UIEC Exhibit COS 2.1 (MEB-1) and UIEC Exhibit COS 2.2 (MEB-2)].

2. At the time the 12CP-75%/25% allocation method was adopted, the PacifiCorp system had a much flatter load shape, with much less seasonality. In fact, to the extent that seasonality was present, winter period peaks were predominant, and not summer period peaks, as is the case today [see UIEC Exhibit COS 2.1 (MEB-1) and UIEC Exhibit COS 2.2 (MEB-2)].

3. The major factor driving the predominance of the summer peak loads for the system and for Utah is growth in residential summer peak loads.

4. Residential customers, and to a somewhat lesser extent Schedule 6 customers, are largely responsible for the annual summer peaking characteristic of PacifiCorp and of RMP in Utah, and as well as for the large day-night swings in load [see UIEC Exhibit COS 2.3 (MEB-3), UIEC Exhibit COS 2.4 (MEB-4) and UIEC Exhibit COS 2.5 (MEB-5)].

5. According to PacifiCorp's planning documents, the summer peak load is the driving factor for capacity additions because loads at other times are substantially lower than during the summer and do not contribute to the reliability driven need to add generation capacity.

6. According to the Loss of Load Probability ("LOLP") studies presented in Appendix I of PacifiCorp's 2013 IRP, 90% of the loss of load hours occurred during the summer months of June through September. Months outside of this period have little or no contribution toward the potential for loss of load. This further demonstrates the cost-causative nature of summer peak demands as opposed to demands in any other months.

7. There is no reason that the methods used to allocate costs among customer classes in Utah should be the same as the methods used to

allocate costs among jurisdictions. In fact, they should and must be different. Jurisdictional allocations have largely been a compromise designed to satisfy specific issues raised by participants in allocation cases, and to afford PacifiCorp a reasonable opportunity to collect 100% of its costs.

8. The 12CP-75%/25% method is not grounded in cost-causation and should not be applied to allocation of costs among customer classes.

9. Other PacifiCorp states have not felt compelled to apply the jurisdictional allocation methodology when allocating costs among customer classes within the state. Notably, California, Oregon and Washington use different methods.

10. The fact that: (1) power prices in the wholesale market are higher in the summer than in other months; and (2) generation costs are higher in the summer than in other months also are reasons supporting emphasis on summertime loads in the allocation of costs.

11. The existing seasonal rate design in RMP's Utah rates is an inherent acknowledgement of the greater importance of summer loads. Summer prices are higher than prices during the winter. For example, Schedule 9 summer demand charges are 48% higher than the demand charges in the winter, and the Schedule 9 summer energy charges are 33% higher than the energy charges in the winter. If RMP and the Commission did not believe summer loads were more costly to serve, this rate pattern clearly would not exist. Now is the time to recognize this fact in the allocation of costs to classes.

12. Allocation of costs using summer peak demands and recognizing seasonal differences in NPC variable costs should be the basic benchmark for developing a revenue spread in this case. UIEC Exhibit COS 2.6 (MEB-6) presents a summary of the cost of service studies that we have prepared. Schedule 9 customers either deserve a decrease, or require only a small increase, to move rates to properly determined cost of service.

13. The most appropriate basis for allocation of costs to customer classes is the 4CP method, with monthly energy cost differences recognized in the allocation.

14. The monthly variable cost component of NPC that is used in the cost of service studies should be used to establish the monthly base values for

the EBA if the EBA remains in its current form. These costs should then in the future be identified monthly and reconciled monthly.

15. In addition to tracking the variable cost component of NPC, consideration should be given to separating the EBA process from general rate cases so that variable costs can be determined and evaluated in separate proceedings using actual historical costs. This would obviate the need to utilize forecasts, and would provide a more accurate and streamlined process by dealing with only historical data, rather than projections.

16. In no event should the increase to Schedule 9 in this proceeding be higher than the overall jurisdictional average percentage increase.

<u>Docket No. 13-035-196:</u>

1. RMP proposes to make use of the standby rate, Schedule 31, mandatory for certain customers. Customers should not be forced to take Schedule 31 service from RMP. Rather, a cost-based standby rate should be available for use by customers who wish to purchase standby power from RMP.

2. RMP's standby reservation charges (referred to as facilities charges) are excessive.

3. RMP inappropriately applies a 13% reserve margin component to its calculated generation cost in order to develop a standby reservation charge. This charge should be calculated based on a much lower reserve or forced outage rate, namely 3%, in order to properly recognize that some standby customers may have reliability much greater than the average of RMP's facilities.

4. RMP overstates the transmission component by not recognizing that the charges should be multiplied by a forced outage rate in order to reflect probable use of the transmission system, in the same way that probable use of generation is calculated.

5. The standard provision for maintenance of customer facilities is a maximum of 30 days per year to be taken in one or two continuous 15-day periods. This is far too restrictive and does not recognize that customers with multiple machines may require consecutive or staggered outages in order to perform proper maintenance, while maintaining a reasonable level of operations. Further, it does not allow for multiple shorter-term scheduled outages which may be necessary. This provision should be changed to allow for 30 days per year per generating unit, scheduled by mutual agreement.

6. RMP does not consistently use standard industry terminology in referring to service supplied to self-generating customers. In practice (and consistent with PURPA definitions) the term "standby" applies to the subcategories of "backup" and "maintenance." Backup power refers to power taken by the customer as a result of forced outages, whereas maintenance power refers to power taken by the customer as a result of scheduled maintenance outages. RMP should modify the language in its tariff to be consistent with this terminology.

7. The development of my proposed standby rate values using embedded costs for the generation component, and the Open Access Transmission Tariff ("OATT") for transmission as recommended by Dr. Lesser, is shown in UIEC Exhibit COS 2.8 (MEB-8) and a tariff red-lined to RMP's proposed rate is shown in UIEC Exhibit COS 2.9 (MEB-9).

CLASS COST OF SERVICE AND DESIGN OF SCHEDULE 9

System and State Loads have a Summer Peaking Characteristic that has Important Implications for Cost Allocation

Q PLEASE DESCRIBE THE LOAD CHARACTERISTICS OF PACIFICORP AND ALSO OF THE UTAH JURISDICTION.

A Both PacifiCorp and the Utah jurisdiction exhibit a dominant summer peaking characteristic.

Q HAVE THESE SYSTEMS ALWAYS BEEN SUMMER PEAKING?

A No. UIEC Exhibit COS 2.1 (MEB-1) shows the monthly peaks for the PacifiCorp system from 1990 through more recent time periods. In contrast to the current summer peaking characteristic of the system, note that at one time PacifiCorp's system was characterized by a winter peak. Transitionally, there were years when both summer peaks and winter peaks were prominent. More recently, however, it is the summer peak that has dominated.

Q HOW DO THE LOAD CHARACTERISTICS OF THE UTAH JURISDICTION COMPARE TO THE PACIFICORP LOAD SHAPES?

A As shown on UIEC Exhibit COS 2.2 (MEB-2), the Utah jurisdiction exhibits an even more pronounced summer peaking characteristic than the PacifiCorp system.

Residential and Small Commercial Loads Cause the Summer Peaking Load Shape

Q WHAT HAS HAPPENED ON THE SYSTEM TO CAUSE THIS CHANGE FROM WINTER-PEAKING TO SUMMER-PEAKING?

A It is predominately the result of growth in summer loads in Utah.

Q HAVE YOU ALSO EXAMINED THE DAILY, WEEKLY AND ANNUAL LOAD PATTERNS OF THE MAJOR CUSTOMER CLASSES IN UTAH?

A Yes. The graph on UIEC Exhibit COS 2.3 (MEB-3) shows the demands of each of the major classes at the times of the monthly system peaks, UIEC Exhibit COS 2.4 (MEB-4) shows the demands on an hourly basis on the system peak day, UIEC Exhibit COS 2.5 (MEB-5) shows the load pattern over a weekly cycle.

Q PLEASE EXPLAIN THESE GRAPHS.

A UIEC Exhibit COS 2.3 (MEB-3) shows the contributions of classes to each of the monthly peak demands and the overall general system load shape in Utah. Obviously, the residential class summer demands are driving the system load shape. They more than double from their spring lows to the summer peak. Rate Schedule 6 customers experience higher demands in the summer than during other months, but the difference or disparity is not nearly as large as is the case for the residential customers. The loads of Schedule 8, Schedule 9 and Schedule 23 customers are relatively flat.

Q WHAT IS SHOWN ON UIEC EXHIBIT COS 2.4 (MEB-4)?

A It shows how the loads of these same classes vary over the 24 hours of a day. For illustration, the loads on the system peak day for the base year (12 months ended June 30, 2013) have been used. Once again, it is easy to see that it is mainly the residential, and to a lesser extent Schedule 6, customers who drive the daily system load shape. It is these loads for which RMP contracts for high cost seasonal power purchases and/or runs high cost peaking units. The peaking units have an annual ownership cost as a result of being on RMP's books, and much of the purchased power is for at least 16 hours a day, six days a week, even though the power may not be needed for all of these hours, and may not be needed at all on other days.

Q PLEASE EXPLAIN UIEC EXHIBIT COS 2.5 (MEB-5).

A It shows the hourly loads during the peak summer week for the base year for the total Utah jurisdiction and for Schedule 9. The graph begins at 12:01 AM on Sunday, June 23, 2013 and continues through 12:00 AM on Saturday, June 29, 2013. Note that over this entire week, there is only a small variation in the loads of Schedule 9 customers.

The line at the top of the graph shows the variations in the loads of the entire Utah jurisdiction. Since Schedule 9 customer loads are relatively constant, it is obvious that the other customer classes are causing this load shape. Essentially, from midnight to the afternoon peak, the load swings from approximately 2,500 megawatts to 4,500 megawatts, a swing of 2,000 megawatts, or 80% from the daily low to the high.

These kinds of loads are very expensive to serve because the cost of having the capacity necessary to serve the peak is extremely expensive since it is not extensively utilized in non-peak times. This makes the unit costs of these purchases and generation very high.

Q ARE THE PATTERNS WHICH YOU HAVE SHOWN FOR THE 12 MONTHS ENDED JUNE 30, 2013 TYPICAL, OR ARE THEY UNIQUE TO THIS PERIOD OF TIME?

A They are typical. For example, please refer to Exhibit UIEC ____ (MEB-4A) and Exhibit UIEC ____ (MEB-4B) from Docket No. 11-035-200, which presented comparable data for the 12 months ended December 2008 and the 12 months ended June 30, 2011. Obviously, the load patterns exhibited in the 12-month period ended June 30, 2013 are typical summer-peaking, and are not abnormal.

Q DOES RMP'S 12CP-75%/25% ALLOCATION METHOD CAPTURE THE COSTS ASSOCIATED WITH THESE KINDS OF LOAD PATTERNS?

A No. The 12CP-75%/25% allocation method employed by RMP does not at all capture the costs associated with these kinds of load patterns. Rather, it effectively socializes the costs associated with the owned and purchased capacity needed to serve these load excursions, and allocates them to everyone, rather than to the cost-causing summer peak loads.

Q YOU PREVIOUSLY HAVE DISCUSSED THE RELATIVE LEVELS OF LOADS IN THE SUMMER MONTHS COMPARED TO OTHER MONTHS. WHAT OTHER IMPORTANT INDICATORS ARE THERE AS TO THE IMPORTANCE OF SUMMER LOADS RELATIVE TO LOADS IN OTHER MONTHS?

A The second factor is discernible from the wholesale power markets, which clearly show that power prices in the summer are higher than power prices at other times. The monthly average generation costs exhibit this same pattern.

A third key factor is how PacifiCorp plans its system in terms of the characteristics it examines in order to determine the need for additional resources. This general relationship was recently confirmed by RMP witness Craig Paice in his May 2012 rebuttal testimony in Wyoming, Docket No. 20000-405-ER-11, at page 6, wherein he stated the following:

> "The cost-causation principle is implemented in COS studies such that costs are classified based on cost-defining service characteristics that are the same or similar to those employed by utility engineers when they make investment decisions."

This acknowledgement further underscores the importance of understanding the basis for system expansion.

Q WHAT IS THE FOURTH FACTOR?

A The fourth factor is discerned from the design of RMP's rates … namely that the major customer classes have summer/winter differentials in their rates.

PacifiCorp System Planning Considerations

Q PLEASE DISCUSS THE PLANNING INDICATORS AND WHAT THEY SHOW.

A They are most clearly laid out in PacifiCorp's 2011 Integrated Resource Plan ("IRP") formally titled "2011 Integrated Resource Plan, PacifiCorp," bearing an issue dated March 31, 2011. (The 2013 IRP is found on the same premises and presents similar data, but not in as much detail).

Q IN THE IRP, WHEN PACIFICORP DEVELOPS ITS CAPACITY BALANCE, WHAT LOADS DOES IT USE?

A This assessment is done using the annual peak demand, which occurs in the summer. In the "Chapter Highlights" portion of Chapter 5 – Resource Needs Assessment (page 83 of the 2011 IRP), PacifiCorp expressed it this way:

> "• On both a capacity and energy basis, PacifiCorp calculates load and resource balances using existing resource levels, forecasted loads and sales, and reserve requirements. The capacity balance compares existing resource capability **at the time of the coincident system peak load hour.**
>
> • For capacity expansion planning, the Company uses a 13-percent planning reserve margin applied to PacifiCorp's obligation (loads plus sales) less firm purchases and dispatchable load control capacity." [Emphasis added.]

In the 2013 IRP, the "Chapter Highlights" portion of Chapter 5 (page 79 of the 2013 IRP) has the same first bullet, and states the second bullet slightly differently to recognize changes that PacifiCorp has made in how it constructs its load and capacity obligation tables. On page 79 of the 2013 IRP, PacifiCorp states:

> "• For capacity expansion planning, the Company uses a 13-percent planning reserve margin applied to PacifiCorp's obligation (Loads – Interruptibles – DSM). The 13-percent planning reserve margin is supported by Stochastic Loss of Load Probability Study in Appendix I."

Throughout the IRP documents, resource needs are evaluated based on the summer peak loads plus a reserve margin of 13%. Loads in all 12 months are not used in the Resource Needs Assessment.

The 2013 IRP Update Report shows the latest forecast data with respect to both annual energy growth and peak load growth. Page 24 of the 2013 IRP Update shows an expected overall energy growth rate of about 1.37% for the PacifiCorp system, and an overall total growth in peak load of about 1.3%. For Utah, the expected growth rate in energy is 2.7% per year and in coincident peak 2.30% per year.

Q WHAT OTHER EVIDENCE DOES THE IRP PROVIDE AS TO THE RELATIVE IMPORTANCE OF LOADS DURING THE SUMMER PERIOD?

A In Chapter 7, PacifiCorp explains various performance measures that it applies when evaluating different candidate expansion plans. For the supply reliability portion of the evaluation, PacifiCorp looks at energy not served ("ENS") as part of the evaluation of the LOLP. At page 198 of the 2013 IRP, Chapter 7 – Modeling Approach, PacifiCorp explains:

> "**Loss of Load Probability**
> Loss of Load Probability is a term used to describe the probability that the combinations of online and available energy resources cannot supply sufficient generation to serve the peak load during a given interval of time.
>
> For reporting LOLP, PacifiCorp calculates the probability of ENS events, where the magnitude of the ENS exceeds given threshold levels. PacifiCorp is strongly interconnected with the regional network; therefore, **only events that occur at the time of the regional peak are the ones likely to have significant consequences.** Of those events, small shortfalls are likely to be resolved with a quick (though expensive) purchase. In Appendix L in Volume II of this report, the proportion of iterations with ENS events in July exceeding selected threshold levels are reported for each optimized portfolio simulated with the PaR

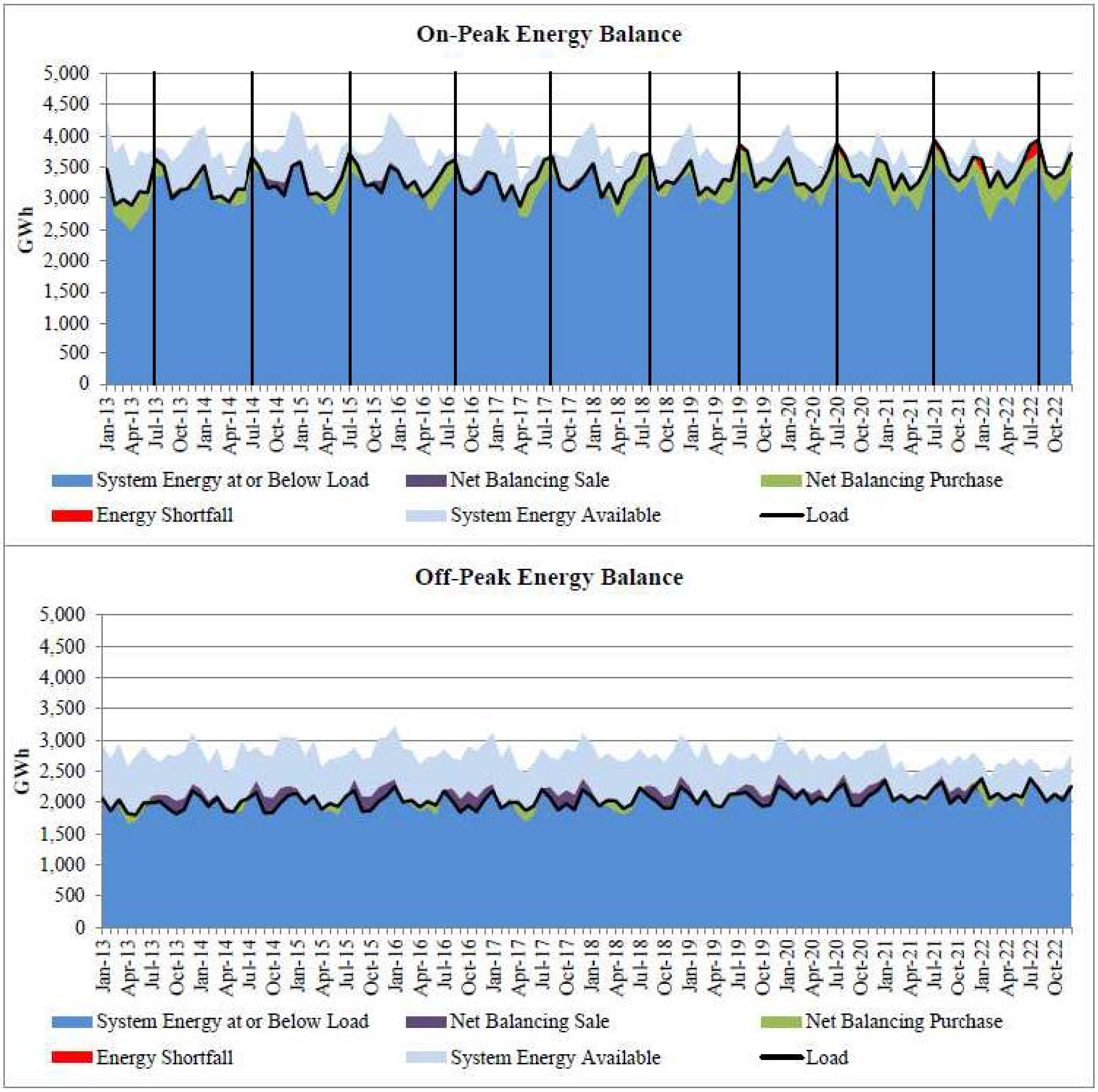
> model. The LOLP is reported as a study average as well as year-by-year results for an example threshold level of 25,000 MWh. This threshold methodology follows the lead of the Pacific Northwest Resource Adequacy Forum, which reports the probability of a "significant event" occurring in the winter season." [Emphasis added.]

Once again, it is clear that the primary concern about loss of load is associated with the summer period when customer demands are the highest and the system is stressed the most. (Also see the subsequent discussion of LOLP and stress factor analysis beginning at page 27 of my testimony.)

Q DID PACIFICORP SUMMARIZE ITS MONTHLY ENERGY POSITION OVER THE PLANNING HORIZON?

A Yes, it did. This appears in graphical format at page 103 in the 2013 IRP. Figure 5.5 – "System Average Monthly and Annual Energy Positions" has been extracted and appears below in the text of my testimony.

Figure 5.5 – System Average Monthly and Annual Energy Positions



Q PLEASE EXPLAIN THIS GRAPH.

A The graph presents the energy position (i.e., whether the amount of energy available is above or below the amount expected to be needed) for on-peak hours and for off-peak hours.

Black vertical lines have been added to the on-peak graph for clarity. These vertical lines clearly indicate that the most crucial times are during the summer peak periods. Although it is difficult to discern from the graph, PacifiCorp reports at page 102 of its 2013 IRP that the first on-peak shortfall appears in July 2018. The graph shows further peak load deficits in 2019, 2020, 2021, and a much greater deficit in 2022.

Notably, the off-peak energy balance does not indicate any shortfalls throughout the forecast period. In addition, it shows that there are frequent opportunities for energy sales, principally during the non-summer periods.

Q IS THERE ADDITIONAL EVIDENCE TO CORROBORATE THIS CONCLUSION?

A Yes. In response to Data Request No. DPU 6.39 in Docket No. 11-035-200, RMP explicitly stated that only summer loads were considered in its resource acquisition planning because only summer loads contributed to a resource adequacy concern.

> **"DPU Data Request 6.39**
>
> **COST ALLOCATION:** Please provide any references in the Company's IRP to the need to acquire new capacity in order to meet peak loads in months other than peak summer months.
>
> **Response to DPU Data Request 6.39**
>
> There are no references in the IRP to meeting peak loads for non-summer months, as the Company's capacity position is based on the system coincident peak load hour, which typically occurs in late July."

Q WHAT IS THE FOCUS OF RMP'S LOAD MANAGEMENT PROGRAMS?

A These programs, also described by RMP as "peak reduction" programs, are "Cool Keeper" and "Irrigation Load Control."[1] Both of these programs allow RMP to implement customer load reductions during the months of June through August. RMP's website promotes Cool Keeper as "…a program designed to help reduce electricity demand during the critical summer months" [Emphasis added.]

Q WHAT DOES THIS INFORMATION DEMONSTRATE ABOUT THE APPROPRIATENESS OF THE 12CP-75%/25% METHOD?

A This information clearly establishes that summer peak demands, and not 12 monthly peaks with a 25% energy weighting, are the drivers of capacity requirements and should be the basis for a cost-reflective allocation.

[1] 2011 Annual Energy Efficiency and Peak Reduction Report, April 27, 2012, at pages 18-22.

RMP's Seasonal Rate Design Clearly is an Acknowledgement of the Greater Importance of Summer Loads

Q YOU ALSO MENTIONED DIFFERENCES IN SUMMER AND WINTER RATES THAT ARE EMBODIED IN RMP'S RATE DESIGN AS BEING FURTHER EVIDENCE OF THE RECOGNITION THAT SUMMER LOADS ARE MORE IMPORTANT THAN LOADS IN OTHER MONTHS OF THE YEAR. PLEASE RECAP THAT EVIDENCE.

A That review indicated that for residential customers the second and third block summer prices are 17% and 46% higher, respectively, than the winter prices. For Schedule 9, the demand charges in the summer are 48% higher than the demand charges in the winter, and the energy charges in the summer are 33% higher than the energy charges in the winter.

If RMP and the Commission did not believe that summer loads are more important than loads in other months of the year, it is unlikely that these kinds of differentials would appear in the rates. The existence of these differentials in the rates is a clear recognition of the greater importance of summer demands as compared to demands in other months of the year.

Q DOES THE FACT THAT THE RATES REFLECT THIS SEASONALITY RESOLVE THE SEASONALITY ISSUE?

A No. While the rates are an attempt to reflect appropriate pricing differentials in the charges, they are based on the costs that are allocated to each rate schedule. Since the allocation of costs between schedules does not recognize the large seasonal differences in loads, and the resulting differences in costs, the end product is rates that also do not recognize these important cost differences.

Classes that have the most accentuated seasonal load patterns are being allocated less costs than they should be, while classes with a more even load pattern are being allocated excessive costs. In other words, the residential customer class, which is predominantly responsible for growth in summer peak demand and in the predominant summer peak load characteristic, is being subsidized by the customer classes with the more stable and non-seasonal load patterns, such as Schedules 8, 9 and 23.

Because of the lack of seasonal cost recognition in the allocation to classes, the rate design becomes an exercise in attempting to find the right way to apportion the wrong set of costs.

This problem can be resolved by adopting appropriate seasonal allocations of both capacity costs and energy costs and reflecting them in the rate schedules.

There is No Reason for Class Cost Allocations to be Tied to Jurisdictional Allocations

Q SHOULD THE ALLOCATION OF COSTS AMONG CLASSES USE THE SAME METHOD THAT IS APPLIED TO ALLOCATE COSTS AMONG STATES?

A No. The jurisdictional allocation protocols always have been a compromise designed to allow PacifiCorp an opportunity to collect 100% of its costs, and should not serve as precedent for cost-causation.

As every participant in this proceeding knows, jurisdictional allocation methods have evolved over time and are the product of trying to accommodate the concerns of a wide variety of parties. There is not necessarily any "cost-causation" basis to this study. Rather, inter-jurisdictional allocations have been more of an effort to provide the utility with an enhanced opportunity to collect 100% of its costs across all jurisdictions, while still accommodating particular jurisdictional priorities and preferences.

In addition, load shape differences between classes within a state are far greater than differences in load shape between jurisdictions. What is an acceptable compromise at the jurisdictional level because of a small impact creates large inequities when applied to classes with widely varying load patterns. Thus, reliance upon an inter-jurisdictional allocation method as a basis for the class cost of service study is inappropriate.

Q IN DOCKET NO. 02-035-04, DID THIS COMMISSION ADOPT THE JAM ALLOCATION METHODS FOR PURPOSES OF ALLOCATION OF COSTS TO CUSTOMER CLASSES?

A No. It explicitly did not adopt the JAM allocators for application in class cost of service studies. In particular, the Commission found as follows at page 40 of its September 14, 2004 Order in Docket No. 02-035-04:

> "Regarding the issue of the impact of the Stipulation and the Revised Protocol on customer classes, the Committee, PacifiCorp and UAE agree the record in this docket is not fully developed on this issue and the Order in this case should not try to resolve it. We concur. We further conclude the Revised Protocol only addresses interjurisdictional cost allocation which means class cost of service will be dealt with in other dockets such as general rate cases."

Q TO YOUR KNOWLEDGE, HAS THERE EVER BEEN AN ANALYTICAL STUDY WHICH DEVELOPED THE 25% ENERGY COMPONENT FOR INCLUSION IN EITHER THE JURISDICTIONAL OR THE CLASS COST ALLOCATION METHODOLOGY?

A To my knowledge there has never been such a study. As I have pointed out in testimony in other cases, the current methodology has evolved over time and represents a compromise among the various state interests. It is not an empirically determined methodology.

Q HAS RMP ACKNOWLEDGED THAT THIS METHODOLOGY WAS ADOPTED AS A "COMPROMISE" FOR JURISDICTIONAL ALLOCATION PURPOSES?

A Yes. In Data Request No. 10.18 in Docket No. 09-035-23, UIEC asked about this:

> **UIEC Data Request 10.18**
>
> **"<u>NPC:</u>**
> Reference is made to studies and analysis done to support utilization of the various transmission assets of PacifiCorp for purpose of determining how those costs should be classified for cost of service studies. Please identify:
> (a) The date of each study;
> (b) The author of each study; and
> (c) Please provide a copy of each study performed to support the classification of the various increments of generation plant at 75% capacity and 25% energy."
>
> **Response to UIEC Data Request 10.18**
>
> "In response to part c, support for use of the 75% demand and 25% energy classification of generation plant is provided in Attachment UIEC 10.18. Other than this, the Company has no other studies responsive to parts a and b."

The following statement appears on page 3 of the referenced attachment:

> "The choice of the 75% demand 25% energy classification for generation and transmission plant was the last allocation decision made by PITA after the merger. The PITA analysis indicated that a wide range of demand and energy classification could be supported on a technical basis. The demand energy classification was the swing issue employed to balance the sharing of merger benefits between all the states and 75% demand 25% energy was selected because it produced an overall cost allocation result that was acceptable to all the states."

This further supports and confirms that the 75%/25% aspect of the methodology was purely a compromise that was crafted to secure agreement among the states for jurisdictional allocation purposes. It was not intended to be applied at the class level and, as noted above, the Commission found in Docket No. 02-035-04 that the Revised Protocol Method (which includes the 12CP-75%/25% methodology) was not applicable to class cost of service studies.

Q ARE YOU FAMILIAR WITH THE COMMISSION'S FEBRUARY 18, 2010 ORDER IN DOCKET NO. 09-035-23?

A Yes, I am.

Q AT PAGE 123 OF THAT ORDER, DIDN'T THE COMMISSION STATE THAT THE 12CP-75%/25% METHOD HAS IN THE PAST BEEN SUPPORTED BY ANALYSES, INCLUDING STRESS FACTOR ANALYSIS?

A Yes. That statement appears in the Commission's Order. The stress factor analysis that was previously presented is out of date as it ended with data for the year 2008. Furthermore, the stress factor analysis did not provide any support for the 75%/25% method, but only purported to support a 12CP allocation methodology. Ancient stress factor analyses cannot be relied upon to support the application of the jurisdictional allocation methodology to the allocation of costs among classes.

Q ARE YOU AWARE OF ANY ADDITIONAL STRESS FACTOR ANALYSIS THAT HAS BEEN CONDUCTED?

A Yes.

Q PLEASE EXPLAIN THAT ANALYSIS.

A As part of the Stipulation approved by the Commission in RMP's most recent rate case, Docket No. 11-035-200, it was agreed that RMP would propose a plan for a stress factor study. Such a plan was proposed, comments were taken and a technical conference was held. This analysis looked at four different factors, namely: (1) firm peak demand each month; (2) number of hours each month that firm load exceeded a specified percentage of the annual peak load; (3) the number of MWh associated with the hours each month that firm load exceeded a specified percentage of the annual peak load; (4) the reserve margin during the peak hour of each month; and (5) the $/MWh difference each month between the cost of wholesale market purchases and the cost of gas-fired resources.

UIEC's comments pointed out that none of the analyses, except the first one, can have any pretention to measuring and determining the criticality of loads on the utility system. The other four analyses are essentially arithmetic exercises that provide no useful information about the hours that are critical.

Dr. Lesser addresses this analysis in more detail in his testimony.

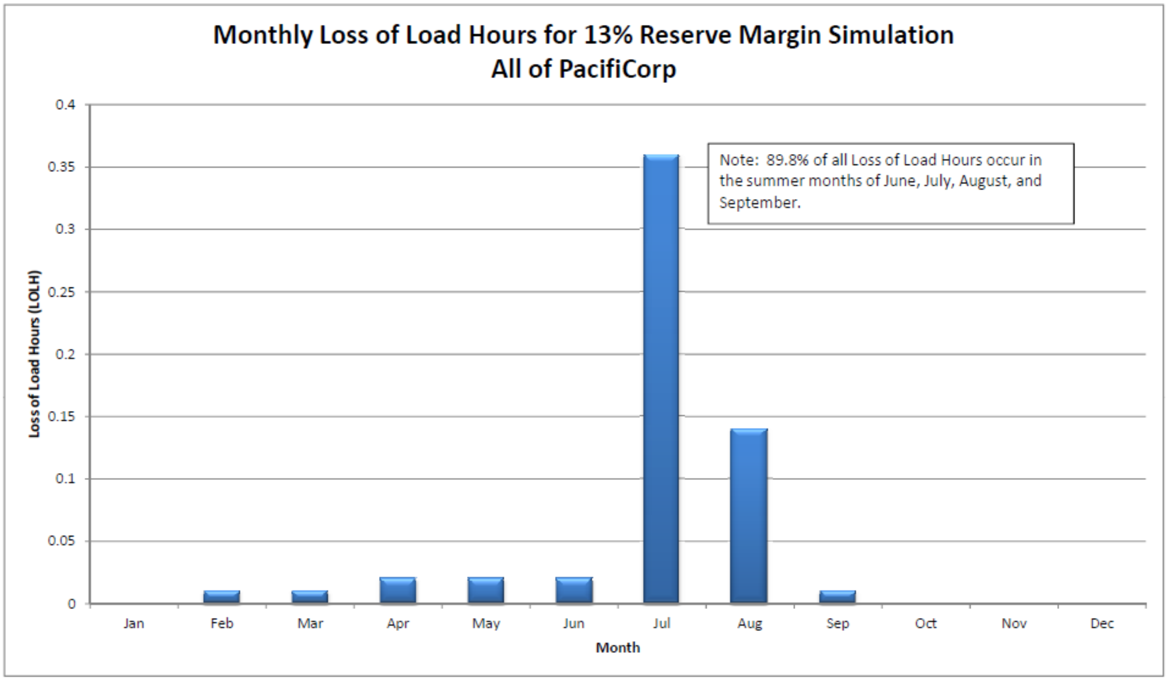
Q IS OTHER INFORMATION AVAILABLE WHICH WOULD BE MORE RELEVANT TO IDENTIFYING CRITICAL HOURS?

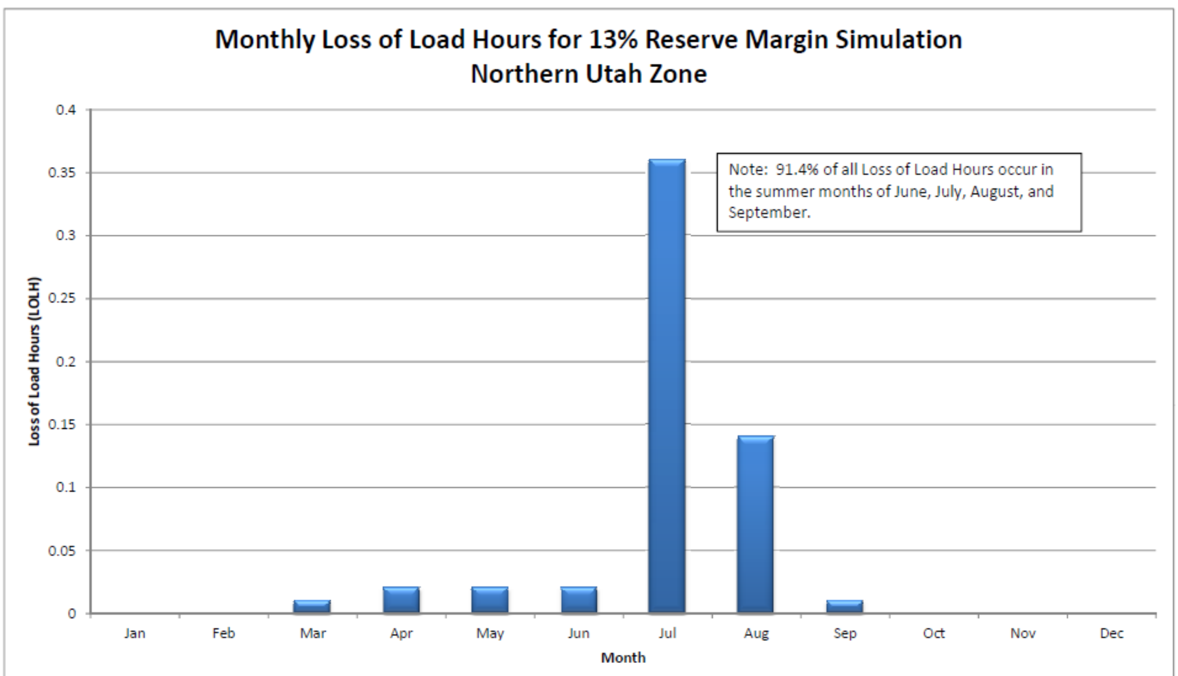
A Yes. The “gold standard” for determining system stress is an LOLP analysis. This is exactly the type of analysis that PacifiCorp conducts as an integral part of its system planning process. It examines the difference between system resources and firm system loads under a variety of conditions, measured by probabilistic techniques that examine a range of values with respect to such important factors as system load, weather conditions, generation unit availability and other key factors.

Q PLEASE DESCRIBE THE CURRENT LOLP EVIDENCE THAT IS AVAILABLE.

A In response to Sierra Club Data Request 3.9, PacifiCorp provided the workpapers supporting the results of the LOLP study presented in Appendix I of its 2013 IRP. The workpapers contain monthly data for all of the resources utilized in the study, including units that represent energy not served (“ENS”). These units only run after all other resources have been dispatched, thus their usage is representative of energy that would not be served by PacifiCorp. The number of hours that these units run represents the duration of hours that load would not be served. The industry standard is “1 in 10,” which equates to 2.4 hours loss of load per year. (Note that all simulation of reserve margins between 10% and 20% meet this standard) Because PacifiCorp belongs to the Northwest Power Pool ("NWPP"), it is allowed to receive energy from other participants in the NWPP for the first hour after a unit outage; therefore, the total number of hours that the ENS units run does not equal the Loss of Load Hours ("LOLH"). The model used is an hourly model, therefore the LOLH can be calculated as the number of hours that the ENS units run, minus one hour times the number of starts from the ENS units.

Using the information contained within the workpaper, we created graphs showing that the vast majority of hours in which energy would not be served occur in the summer months. (The graphs only contain information regarding the simulation of a 13% reserve margin, as this is the reserve margin that PacifiCorp is planning to meet.) In all of PacifiCorp, 90% of all LOLH occur in June through September and for the Northern Utah Zone alone, 91% occur in the summer. The Northern Utah zone accounts for all of the LOLH in PacifiCorp for the months March through September (there is a negligible amount of LOLH that occurs in February in the Northeast Wyoming zone in February).


Monthly Loss of Load Hours for 13% Reserve Margin Simulation
All of PacifiCorp
Note: 89.8% of all Loss of Load Hours occur in the summer months of June, July, August, and September.
Loss of Load Hours (LOLH)
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35
0.4
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month


Monthly Loss of Load Hours for 13% Reserve Margin Simulation
Northern Utah Zone
Note: 91.4% of all Loss of Load Hours occur in the summer months of June, July, August, and September.
Loss of Load Hours (LOLH)
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35
0.4
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month

Q WHAT DO YOU CONCLUDE FROM THE ANALYSIS OF LOLP AND OTHER FACTORS?

A This analysis clearly demonstrates that the only critical peak time on the PacifiCorp system is the summer peak period. Accordingly, proper cost of service and rate design principles require that costs be allocated based on customer class contributions to summer peak demands, and not to demands in other months, and not on the basis of energy consumption.

Q DID THE COMMISSION ALSO STATE THAT PARTIES WHO WANT TO PROPOSE AN ALTERNATIVE MUST PROVIDE ANALYSIS TO DEMONSTRATE THAT THE METHOD IS ALSO APPROPRIATE AND VIABLE AT THE INTER-JURISDICTIONAL LEVEL?

A Yes. That statement appears in the Order.

Q ARE YOU URGING THE COMMISSION TO CHANGE THIS REQUIREMENT?

A Yes. I believe the evidence that has been presented in this case clearly demonstrates that adherence to the jurisdictional allocation methodology when allocating costs between customer classes within a jurisdiction is ill-advised. Continued application of the inter-jurisdictional methodology at the intra-jurisdictional level to allocate costs among customer classes simply ignores the overwhelming evidence about the importance of summer peak loads, particularly in Utah. And, as I note subsequently, three of PacifiCorp's other jurisdictions do not feel compelled to mimic the inter-jurisdictional allocation for class cost of service purposes, but rather have adopted their own methodologies which they believe to be cost-reflective for their states.

Q DO YOU HAVE ANY ADDITIONAL EVIDENCE TO SUPPORT YOUR POSITION?

A Yes. In the 2010 phase of Docket No. 02-035-04, PacifiCorp participated in a settlement of its most recent filing to modify the inter-jurisdictional cost allocation protocol.[2] I believe two paragraphs in the settlement are of particular note, Paragraph 3 and 18.

Q WHAT DO THESE PARAGRAPHS STATE?

A Paragraph 3 states as follows:

> "3. In this Application, PacifiCorp also acknowledges that state regulatory commissions are obligated to establish just and reasonable rates under a state's regulatory law and public policy. Accordingly, the 2010 Protocol explicitly acknowledges that 'Nothing in the 2010 Protocol shall abridge any State's right and/or obligation to establish fair, just and reasonable rates based upon the law of the State and the record established in rate proceedings conducted by that State.' "

[2]Agreement Pertaining to PacifiCorp's September 15, 2010 Application for Approval of Amendments to Revised Protocol Allocation Methodology, Utah PSC Docket No. 02-035-04, June 22, 2011.

Paragraph 18 states as follows:

> "18. **The Parties agree that no part of this Agreement, or any Commission Order acknowledging, adopting, approving or responding to the same, shall in any manner be argued or considered by any Party hereto as binding or as a precedent in any Utah rate setting context or case with respect to interclass allocations.** Every Party to this Agreement hereby agrees not to claim or argue that execution or approval of this Agreement or adoption or use of the Rolled-In inter-jurisdictional allocation methodology in Utah requires or established a presumption in favor of any particular Utah interclass allocation methodology, practice or policy, or any changes to current Utah interclass allocation methodologies, policies or practices." [Emphasis added.]

I believe these statements make it absolutely clear that the inter-jurisdictional allocation method is not to be considered as precedent for the allocation of costs among customer classes.

Q DID THE COMMISSION APPROVE THE SETTLEMENT AGREEMENT?

A Yes. It did so in an Order dated February 3, 2012.

Q DO OTHER PACIFICORP STATES FEEL COMPELLED TO FOLLOW THE INTER-JURISDICTIONAL COST ALLOCATION METHODOLOGY?

A No. The states of California, Oregon and Washington all use a method for allocation among classes that is different from the inter-jurisdictional cost allocation methodology.

Q PLEASE EXPLAIN HOW CALIFORNIA ALLOCATES COSTS AMONG CUSTOMER CLASSES.

A In California, costs are allocated among customer classes using marginal cost to determine a basis for the allocation of embedded cost revenue requirements among classes. There is no relationship between this method and the jurisdictional allocation method.

Q HOW IS IT DONE IN OREGON?

A Oregon, like California, uses a marginal cost methodology to develop factors to allocate embedded cost revenue requirements among classes. There is no relationship between this method and the jurisdictional allocation method.

Q AND HOW ABOUT IN THE STATE OF WASHINGTON?

A In the state of Washington, generation and transmission fixed costs are allocated to classes using an average of the contribution of the classes to the top 100 hours of load in the summer and the top 100 hours of load in the winter. In other words, Washington uses a peak responsibility method. There is no relationship between this method and the jurisdictional allocation method.

Class Cost of Service Studies

Q HAVE YOU PREPARED CLASS COST OF SERVICE STUDIES WHICH GIVE MORE WEIGHT TO SUMMER PEAK DEMANDS?

A Yes. These studies are summarized on the summary page of UIEC Exhibit COS 2.6 (MEB-6) and detailed on the schedules which are a part of UIEC Exhibit COS 2.6 (MEB-6).

There is a separate schedule for each cost of service study. The first page presents results based on current revenues, and the second page presents results using the same target return on rate base that RMP has requested. Use of the same target return on rate base and other RMP-proposed revenue requirement components is only for the purpose of being able to compare just the cost of service methodologies, rather than both cost of service methodologies and potential differences in revenue requirement. These are in the same format as Ms. Steward's exhibits.

Q WHAT SUMMER CP STUDIES ARE YOU PRESENTING?

A Schedules 1 and 2 show the results of a two summer CP study and a four summer CP study, respectively. The results are very close, and very different from RMP's 12CP-75/25 study.

<u>Seasonal Allocation of Costs</u>

Q YOU HAVE DISCUSSED IN DETAIL THE IMPORTANCE OF SUMMER DEMANDS FOR PURPOSES OF ALLOCATING FIXED COSTS. DO VARIABLE COSTS ALSO DIFFER SEASONALLY?

A Yes, these costs also differ seasonally.

Q DOES RMP APPROPRIATELY TREAT THESE SEASONAL VARIATIONS IN ENERGY COSTS?

A No. RMP makes no attempt, at either the jurisdictional level or the class level, to account for seasonal cost variations in its allocation of energy costs.

Q WHAT VARIABLE COST COMPONENTS OF NPC DOES RMP ALLOCATE ON AN ENERGY BASIS?

A RMP allocates variable costs in FERC Accounts 501, 503, 547, 555-Energy, and 565-Energy on an energy basis.

Q HOW DOES RMP ALLOCATE THE VARIABLE COMPONENTS OF NPC TO UTAH?

A To allocate the variable cost components of NPC to Utah, RMP uses a single annual percentage allocator. This allocator is derived from the ratio of Utah annual kWh to PacifiCorp annual kWh. This annual allocator is applied to PacifiCorp's annual energy costs to obtain adjusted annual Utah variable costs. This approach obviously does not recognize seasonal variations in energy costs in any respect, and is not consistent with cost of service principles.

Q HOW ARE THESE VARIABLE COSTS ALLOCATED TO CLASSES?

A These adjusted annual Utah variable costs are then allocated to classes based on class annual kilowatthours as a percentage of total Utah annual kilowatthours. This single annual allocation factor for each class is identified by RMP as the respective class F30 cost factor in its cost of service study. RMP uses the class F30 factors to allocate the variable costs associated with each FERC account identified above to the classes.

Q HAVE YOU DEVELOPED AN ALLOCATION OF NPC TO RETAIL CUSTOMER CLASSES THAT PRESERVES THE SEASONAL NATURE OF NPC?

A Yes. This analysis appears on Schedule 3 of UIEC Exhibit COS 2.6 (MEB-6).

Q WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A I conclude that the monthly differences in energy cost are too important to be ignored. They should be incorporated in the class cost of service studies as I have done, should be incorporated in EBA monthly values, and also should be tracked monthly. In other words, reconciliations between base and actual values should occur each month in order to track costs properly.

My recommendation and approach are consistent with the Commission's recent order:

> "Regarding the Company's concerns of additional [monthly] filing requirements in general rate cases, we concur with the Division, implementation of the EBA requires additional detail to be provided either in testimony or in the compliance NPC filing as described in our May Order; however, this does not present a new "filing requirement" for a general rate application to be considered a "complete" filing. Rather, it is information <u>now necessary to determine the base Utah monthly net power cost and wheeling revenue approved in the general rate case</u>." (Report and Order on EBA Filing Requirements, Docket No. 09-035-15, June 15, 2012 at 12 [Emphasis added.])

Q HAVE YOU PREPARED ANY COST OF SERVICE STUDIES BASED ON THE USE OF SUMMER CLASS DEMANDS FOR THE PURPOSE OF ALLOCATING THE FIXED COSTS ASSOCIATED WITH THE GENERATION AND TRANSMISSION SYSTEMS, AND WHICH RECOGNIZE SEASONAL VARIATIONS IN VARIABLE COSTS?

A Yes.

Q WHERE DO THESE STUDIES APPEAR?

A The two coincident peak study is shown on Schedule 4 and the four coincident peak study is shown on Schedule 5 of UIEC Exhibit COS 2.6 (MEB-6).

Q HAVE ANY OTHER COST OF SERVICE STUDIES BEEN PREPARED?

A Yes, we have also prepared studies using eight monthly coincident peaks (“8CP”).

Q WHAT IS THE BASIS FOR THE 8CP STUDIES?

A If, despite the overwhelming evidence to the contrary, there is a desire to broaden the period used for cost allocation by including winter peak hours, then the months of January, February, November and December would be added to the four summer peak months in developing the allocation factors.

Q WHERE DO THESE STUDIES APPEAR?

A The 8 CP study without the monthly NPC factor appears as Schedule 6, and the 8 CP study with the monthly adjustment to the NPC factor appears as Schedule 7.

Q HAVE ANY OTHER COS STUDIES BEEN PREPARED?

A Yes. Although I believe the evidence shows that all fixed costs should be allocated strictly on class demands without any energy weighting, for illustrative purposes, we have prepared versions of these studies with a 25% energy weighting in the allocation of fixed costs. These are included as Schedules 8 through 13 of UIEC Exhibit COS 2.6 (MEB-6).

The results for Schedule 9 are summarized and compared to RMP's study on the summary page of UIEC Exhibit COS 2.6 (MEB-6).

Q PLEASE EXPLAIN WHAT YOU CONCLUDE FROM THESE VARIOUS COST OF SERVICE STUDIES.

A If a proper cost of service study is used, Schedule 9 requires either a smaller increase, or a decrease, to move to system average rate of return.

Based on this evidence, Schedule 9 should not receive a percentage increase in rates as a result of this case that exceeds the system average percentage increase.

Design Considerations for Schedule 9

Q RMP HAS PROPOSED TO APPLY AN EQUAL PERCENTAGE INCREASE TO EACH OF THE CHARGES IN SCHEDULE 9. DO YOU HAVE ANY COMMENTS ABOUT THAT?

A I generally agree with the application of an equal percentage adjustment (whether an increase or a decrease) to each of the current charges in order to develop the rates resulting from this rate case, but recommend that all of any increase be derived from increasing only the summer charges.

In addition, I propose a change to the summer/winter split on Schedule 9.

Q PLEASE EXPLAIN.

A The current summer period is the months of May through September, and the winter period is the months of October through April. A review of the monthly peak load data shown in UIEC Exhibit COS 2.1 (MEB-1) and UIEC Exhibit COS 2.2 (MEB-2) reveals that the high load months on both the PacifiCorp system and on RMP's system in Utah is restricted to the months of June through September. The month of May is not one of the highest load months either on the system, or in Utah. Accordingly, it would be appropriate to move the month of May out of the summer peak period into the winter peak period. This would slightly increase the rates in the summer and decrease them in the winter so as to maintain the overall collection of demand costs the same as under the current summer/winter rate demarcations.

This should apply to Schedule 8 as well, and to other schedules, subject to any rate impact considerations.

<u>EBA Considerations</u>

Q PLEASE ELABORATE ON THE REFLECTION OF THESE COSTS INTO THE EBA.

A The seasonal characteristic of NPC should be carried through from the total Company level to Utah, as I have described. This will help preserve the integrity of the seasonal variation in net NPC, be a better reflection of cost of service, and provide better price signals when carried through to monthly reconciliations.

Q THE USE OF COINCIDENT PEAK ALLOCATION FACTORS TO ALLOCATE SOME OF THE DEMAND-RELATED COSTS COMPLICATES MONTHLY ALLOCATIONS. HOW DO YOU DEAL WITH THAT?

A There are two ways. One way is to develop a set of relationships between energy allocators and demand allocators, based on either historic observed data or on projections. This would allow the monthly coincident peak allocator to be derived quickly once the energy allocator is known.

Alternatively, and preferably, demand-related costs could be retained in base rates without a tracking feature. Because some of the demand-related elements are revenues and some are expenses, they offset to a significant extent. The result is that the variable costs constitute over 80% of the total NPC in this case.

Tracking only the variable cost component in the EBA reduces its complexity since these costs are directly a function of energy consumption and the allocation factors can be determined expeditiously. This approach also is consistent with how EBAs or fuel adjustment clauses ("FAC") work in most other states.

Q ARE THERE ANY OTHER RECOMMENDATIONS THAT YOU HAVE FOR THE EBA?

A Yes. Consideration should be given to separating the EBA cost determination, tracking and reconciliation from general rate cases. EBA issues consume a substantial amount of time and involve complex modeling and extensive adjustments. The complexity could be reduced by tracking only the variable component of cost as I have indicated. The process also could be simplified and the burden of forecasting reduced by moving to a historical-based EBA, wherein the EBA value contains 100% of the EBA-related costs that are being tracked. In the future, the actual costs incurred for the corresponding components would be determined and become the new EBA factor for the month or other period of time that it would be in effect. I urge the Commission to give consideration to this approach as a possible modification.

SCHEDULE 31 – STANDBY SERVICE

Q HAVE YOU REVIEWED THE UPDATED TESTIMONY AND EXHIBITS OF RMP WITNESS JOELLE STEWARD CONCERNING THE PROPOSED DESIGN FOR SCHEDULE 31 – STANDBY SERVICE?

A Yes, I have.

Q RMP PROPOSES THAT CUSTOMERS WITH SELF-GENERATION FALLING INTO CERTAIN CATEGORIES BE REQUIRED TO TAKE STANDBY SERVICE UNDER SCHEDULE 31. DO YOU AGREE WITH THIS REQUIREMENT?

A No. The customer should not be mandated and obligated to take standby service from RMP. Rather, RMP should offer cost-based standby rates which offer both backup and maintenance service under reasonable terms and conditions. Customers desiring to take such service from RMP should be allowed to do so, but not required to do so.

Q DOES DR. LESSER ALSO OFFER TESTIMONY ON STANDBY SERVICE?

A Yes. Dr. Lesser presents an alternative standby service rate that includes a market-based supply component and a transmission component based on PacifiCorp's OATT.

Q WHAT IS THE DIFFERENCE BETWEEN YOUR APPROACH AND DR. LESSER'S?

A Dr. Lesser develops a standby rate with a market-based supply component, while I develop a standby rate based on Utah PSC embedded cost revenue requirement. Customers should have the opportunity to take standby service under either alternative.

Q DO YOU AGREE WITH MS. STEWARD'S PROPOSED DESIGN FOR SCHEDULE 31?

A No. I disagree with her proposals in several major respects. Many of the important charges in the proposed rate are excessive, especially the reservation charge as applied both to generation costs and transmission costs. Also, the terms and conditions, especially those pertaining to scheduled maintenance, are unnecessarily rigid and inflexible.

Q HOW WILL YOU PROCEED WITH THIS PORTION OF YOUR TESTIMONY?

A I will begin my testimony with a general discussion of standby rates and the principles which should govern their design and application. I will follow this by my specific criticisms of RMP's proposals, and provide my recommended design considerations and rate parameters.

Overview of Standby Costing Principles

Q WHAT IS STANDBY SERVICE?

A Standby service is electric power and energy supplied by an electric utility to replace electric power and energy that is normally provided by a customer's self-generation facility. Thus, whereas non-generating customers purchase their full requirements ("FR") from an electric utility, self-generating customers ("SGC") are partial requirements ("PR") customers of an electric utility.

Q WHAT TYPES OF SERVICE DOES RMP OFFER TO SGC'S?

A It offers two types of standby service, namely backup service and maintenance service.[3] It also offers supplemental service.

Q WHAT IS BACKUP POWER?

A Backup power is electric energy or capacity which is supplied by an electric utility to replace energy ordinarily generated by a SGC's own generation equipment during an unscheduled outage of the SGC. Thus, backup power is supplied by the utility on a random basis directly associated with self-generator equipment failures.

Q WHAT IS MAINTENANCE POWER?

A Maintenance power is electric energy or capacity supplied by an electric utility during scheduled outages of the SGC generation. This type of power would normally be provided on a pre-arranged, scheduled basis to allow the customer to take its equipment out of service for routine inspections and preventive maintenance.

[3] RMP sometimes uses the terms "standby" and "backup" interchangeably and inconsistent with both industry standard terminology and with the definitions in PURPA. I will use industry standard terminology in my discussion, except where referring to a particular provision of RMP's tariff or explanation, it is necessary to use RMP's terminology.

Q WHAT IS SUPPLEMENTARY POWER?

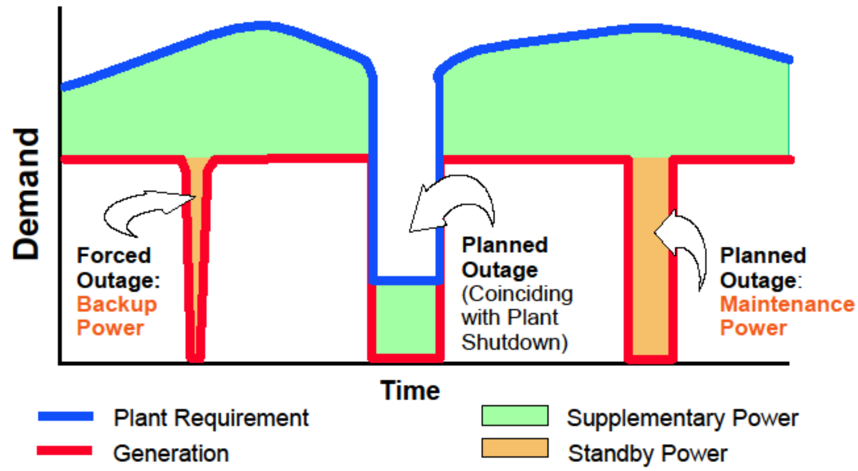
A Supplementary power is power that is purchased in addition to standby service. It is similar in character to the FR service provided to non-generating customers.

Q CAN YOU ILLUSTRATE THE DIFFERENCES BETWEEN SUPPLEMENTARY, BACKUP AND MAINTENANCE POWER?

A Yes. The following diagram illustrates the relationship between supplementary, backup and maintenance power. The blue curve at the top represents total electricity requirement of an SGC. The red line represents the electricity normally generated by an SGC's own facilities. When generating units are operational, an SGC may require only supplementary power, as indicated by the green shaded area. As shown in the middle of the diagram, even when the generating units are completely shut down, the SGC may still be purchasing only supplementary power assuming that there is a corresponding load reduction associated with the equipment outages.

Backup and maintenance power are depicted in the orange areas. (The time scale has been exaggerated to illustrate the concepts.) They are required only when an SGC needs to purchase electricity to replace power and energy that is normally self-generated. Backup power is purchased during forced outages, while maintenance power is purchased during outages which are usually planned in advance.

Illustration of a Self-Generator's Purchase Requirements



Q WHEN DO FORCED OUTAGES OCCUR?

A Forced outages usually occur because of sudden, unanticipated equipment failures. As with the generators owned and operated by PacifiCorp, forced outages occur randomly and usually for only a very short duration.

Q ARE PLANNED OUTAGES DIFFERENT THAN FORCED OUTAGES?

A Yes. Planned outrages, by definition, are pre-arranged in advance. There are two types of planned outages. First, because not all operating problems require immediate attention, it may be possible to defer an outage from on-peak to off-peak hours, when the utility typically has more resources available. These types of planned outages may occur with only several days' lead time, or less. Second, all generating units must be removed from service periodically for maintenance. Maintenance outages usually must be planned well in advance because of the SGC's production and manpower requirements, and the need to coordinate the maintenance outages with the utility.

Q PLEASE ELABORATE ON THE DIFFERENCES BETWEEN BACKUP POWER AND MAINTENANCE POWER; AND REGULAR UTILITY SERVICE, OR SUPPLEMENTARY POWER.

A Maintenance power is pre-scheduled in advance with the utility. When the utility agrees to supply maintenance power, it is because it expects to have adequate resources available. Further, both the amount of maintenance power and the duration of the outage are usually known quantities. FR customers, by contrast, use power throughout the year, not just during periods when the utility has adequate resources. They are not required to coordinate their electricity use with the utility in advance, nor are they required to specify the duration of use.

As previously noted, equipment failures, which could require an SGC to purchase backup power, occur on a random basis. Unlike FR customers who continuously purchase some amount of electricity year-round, SGCs purchase backup power intermittently when the customer's generation is inadequate to meet the total requirements. Backup power, thus, is based on the principle that the customer is providing the capacity normally satisfying the customer's load, while the utility is providing the reserve capacity.

Q IS THIS "RESERVE" PRINCIPLE CONSISTENT WITH HOW A UTILITY PROVIDES SERVICE TO ITS FIRM CUSTOMERS?

A Yes. Page 1 of UIEC Exhibit COS 2.7 (MEB-7) illustrates an example of a utility providing firm capacity and energy to non-generating customers. Assuming each light bulb were to represent 1,000 kilowatts (kW) of firm demand, the utility would install 10,000 kW (the amount of capacity equal to the firm demand), plus additional reserve capacity to ensure that continuous service is provided. (The utility-owned capacity is depicted in green.) The utility with a 13% required reserve margin, thus, would have to install 11,300 kW of capacity. What this means is that non-generating customers with a total firm load of 10,000 kW would pay the utility for 11,300 kW (10,000 kW associated with the load and 1,300 kW associated with the reserve.)

By contrast, an SGC with a load of 10,000 kW is different, as illustrated in page 2 of UIEC Exhibit COS 2.7 (MEB-7), because this customer is providing the 10,000 kW of capacity to serve its own load. (Customer-owned generation is depicted in orange.) The utility is called upon only to provide reserve capacity (depicted in green). Assuming the SGC to be equally reliable as the utility's own generating units, it should pay for only 1,300 kW of reserve capacity.

Q IS THE LEVEL OF REQUIRED RESERVE A FUNCTION OF GENERATOR RESOURCE RELIABILITY?

A Yes, it is. A self-generator having greater reliability than utility-controlled resources would require reserves lower than the utility average. On the other hand, a self-generator with below-average reliability could require above-average reserves. A precise determination can only be made by long-run observed performance of the facilities in question.

Q DO MAINTENANCE AND BACKUP POWER IMPOSE THE SAME COSTS ON A UTILITY?

A No, they do not. Maintenance and backup power are different not only from FR service (or supplementary power), but also from each other. It is, therefore, important that the rates reflect these cost differences.

The rates for backup power service should reflect the fact that the utility is only providing the reserve capacity. Maintenance power service rates (for outages that are coordinated with the utility) also should reflect both the lower quality and the off-peak nature of this service. It is a lower quality of service than firm power because utilities generally require maintenance service to be scheduled in advance, and service may be refused if adequate resources are not available to accommodate a planned outage.

Q WHAT CAUSES BACKUP POWER TO BE LESS COSTLY THAN SUPPLEMENTARY POWER?

A Non-generating customers and backup power customers have different load characteristics. Non-generating FR customers use the equivalent of supplementary power throughout the year, while SGCs may require backup power only during random forced outages. Whereas a non-generating FR customer will impose a load on the system 365 days a year, a reliable SGC should require backup power for only a handful of days. ***This means that an SGC's demand is much less likely to coincide with the utility's system peak than a non-generating customer. In other words, backup power will generally have a much lower coincidence factor than supplementary power.***

Q WOULD YOU PLEASE DEFINE THE TERM "COINCIDENCE FACTOR"?

A Coincidence factor is the ratio of coincident peak demand to non-coincident peak NCP, or billing demand. This definition is further illustrated in the following table.

Example Showing the
Concept of Coincidence Factor

Customer Class	Coincident Demand (kW) (1)	Billing or Non-Coincident Demand (kW) (2)	Coincidence Factor[(a)] (3)
FR1	1,000	2,000	50%
FR2	1,000	1,250	80%

[(a)]Column (1) ÷ Column (2).

For purposes of illustration only, both classes take FR service and impose a 1,000 kW coincident demand. FR1 has a non-coincident demand of 2,000 kW, while FR2's non-coincident demand is 1,250 kW. Thus, FR1 would have a 50% coincidence factor (1,000 kW ÷ 2,000 kW), while FR2 would have an 80% coincidence factor (1,000 kW ÷ 1,250 kW).

Q HOW IS THE COINCIDENCE FACTOR RELEVANT TO RATE DESIGN?

A Billing demand is measured on a non-coincident basis using the highest on-peak demand in the billing month. A customer class having a higher coincidence factor will impose higher demand-related costs per kilowatt of billing demand than a class having a lower coincidence factor. This result is illustrated in the following table.

Impact of Coincidence Factor on Demand Charges

Customer Class	Coincident Demand (CP kW) (1)	Billing Demand (BD kW) (2)	Coincidence Factor (3)	Demand Costs[a] (4)	Demand Charge[b] ($/BD kW) (5)
FR1	1,000	2,000	50%	$10,000	$5.00
FR2	1,000	1,250	80%	$10,000	$8.00
Standby	1,000	20,000	5%	$10,000	$0.50

[a]The demand costs are the same because they are allocated relative to coincident demand.
[b]Column (4) ÷ Column (2).

It is assumed that all three classes impose the same coincident demand on the utility and that total demand costs are allocated relative to coincident demand. FR1 and FR2 are FR service with 50% and 80% coincidence factors, respectively. The standby class, by contrast, has a 5% coincidence factor.

The lower the coincidence factor, then, all other things equal, the lower the per unit demand charge. This is because there are more billing units (Column 2) over which to spread the allocated demand-related costs (Column 4) for backup power than for supplemental power (i.e., regular utility) service. Whereas, a $5 or $8 demand charge would be appropriate for FR customers, a reliable standby customer should be charged only a fraction of these amounts, or $0.50, based on the above example.

Q WOULD BACKUP AND MAINTENANCE SERVICE HAVE THE SAME COINCIDENCE WITH THE SYSTEM PEAK AS REGULAR UTILITY SERVICE?

A No. Maintenance power, by definition, would only be provided during off-peak hours or other hours during the year when adequate resources are available. Therefore, maintenance power would have virtually zero coincidence. Forced outages, by contrast, are more random in nature. Whether backup power is more or less coincident than regular utility service would depend on the reliability of self-generating units. Because more reliable units would require less backup power, the expected backup load would be far less than the corresponding standby contract capacity.

Q WHAT IS THE EXPECTED BACKUP LOAD?

A The expected backup load represents the level of demand the utility can expect to serve. Mathematically, it is the equivalent forced outage rate ("EFOR") times the maximum or contract demand for standby service. In some hours, the load will be greater than the expected value; in other hours, it will be less than the expected value; and in many hours, it will be zero. Unlike FR loads, standby customers will generally not place as much of their total contracted demand on the utility during peak periods.

Q WHAT IS THE EFOR OF A GENERATING UNIT?

A In the utility industry, the statistic which best describes reliability is the EFOR. The EFOR is simply a ratio. The numerator is the hours that the facility is out of service as a result of a forced outage, while the denominator is the total hours in the period examined, with consideration given to forced outages which caused the facility to be partially unavailable as well as outages which caused the facility to be completely unavailable.

For example, let's assume that there are 100 hours in the period in question. Further assume that the facility is in service for 95 hours and forced completely out of service for five hours. The EFOR is 5% (5 ÷ 100). Alternatively, let's assume that in a 100-hour period the facility is out of service completely for two and one-half hours as a result of a forced outage and during an additional two and one-half hours is reduced to 50% of its capability as a result of a partial forced outage. The numerator in our fraction is 3.75 (two and one-half hours of full forced outage, plus two and one-half hours times a 50% outage). The EFOR is then 3.75%.

Q DOES THE RELIABILITY OF SELF-GENERATORS AFFECT THE COST OF PROVIDING BACKUP SERVICE?

A Yes. As discussed previously, a utility providing backup service is only incurring the costs associated with the reserve capacity which, in conjunction with the self-generating capacity, will assure a reliable supply of electricity to the SGC. This is analogous to the utility providing one "spare" tire for an automobile and the self-generator supplying the other four tires. However, the need for only one "spare" is a function of the reliability (or, conversely, the failure rate) of the tires. If the tires have a high failure rate, perhaps two "spares" may be needed to provide the desired quality of service. On the other hand, if the tires are extremely reliable, no "spare" may be required. The determination of the level of required reserves for a self-generator (and thus, the associated cost to provide backup service) is similar to the determination of the number of required "spare" tires. Highly reliable self-generators will require small reserve levels; unreliable self-generators will require larger reserve levels.

Q GIVEN THAT STANDBY SERVICE IS DIFFERENT FROM FR SERVICE, IS IT APPROPRIATE TO COST AND PRICE STANDBY SERVICE INDEPENDENT OF A CLASS COST OF SERVICE STUDY THAT SPECIFICALLY ALLOCATES COSTS TO THEM?

A Yes. As described above, standby service is clearly different from FR service. While FR service provided to residential, commercial, industrial and lighting classes tends to follow a consistent pattern from test year to test year, standby service does not. As explained previously, forced outages are random occurrences. There can be many forced outages in some years and few in other years. Maintenance service is also unique in that it is typically scheduled only at times when capacity is adequate. As with forced outages, there may be many maintenance outages in some years and few in other years.

Thus, including the test year demands of standby customers in the cost of service study may result in a higher allocation of demand-related costs when outages are more frequent, and vice versa when outages are much less frequent. This constant shifting of cost responsibility will have the undesirable effect of causing both the FR and standby rates to fluctuate from test year to test year.

A preferable alternative is to quantify the amount of reserve capacity required to provide firm standby service based on an expected level of standby demand that the utility will serve over time. This can be done independent of a class cost of service study. Thus, the revenues derived from standby service can then be used to offset the cost of serving the full service customer classes.

Q HOW SHOULD THE COST OF STANDBY SERVICE BE DETERMINED?

A The standard should be the same as for full requirements customers, i.e., for production costs and transmission costs, the contribution to the relevant system coincident peaks. The only difference is that while the contribution for full requirements customers is based on their *observed* demands, the contribution for standby customers should be based on their *expected* demand. It is advisable to use expected demands because the random nature of backup service makes the use of expected demands more predictive of future usage patterns than the use of a single observation.

Q IS THE USE OF EXPECTED DEMANDS OR PROBABILITY ANALYSIS USED IN SYSTEM PLANNING OR IN COST ALLOCATION?

A Yes, it is used in both. For example, system planners often use the standard of a loss of load probability of one day in every 10 years to plan the amount of capacity needed. Moreover, the CP method itself is a probabilistic notion predicated on the fact that cost causing system loads could occur in different months.

Q SUPPOSE THAT IN A CERTAIN YEAR, ONE OR MORE CUSTOMERS USE MORE STANDBY DEMAND THAN THEIR EXPECTED CONTRIBUTION TO THE 12 COINCIDENT PEAKS. ISN'T THAT A PROBLEM UNDER YOUR PROPOSED RATE DESIGN?

A No. In the first place, as a class, the very nature of an expected value means that while there may be a greater than expected demand imposed in one year, there is an equal probability that there will be lower than expected demand imposed in another year. On average, the demand should equal the expected value. Moreover, for those customers that use a greater amount than expected, the daily demand charge will serve to make them pay a cost-based contribution to the revenue requirement.

Q DO YOU SHARE ANY OF THE COSTING PRINCIPLES ESPOUSED BY MS. STEWARD?

A Yes. We both seem to agree that:

- Production reservation charges should reflect the expected coincident load on the system;
- A pro-rated demand charge is an appropriate mechanism to reflect the difference in costs imposed by good performers versus poor performers;
- A SGC should not pay more for standby service than it would have paid under the otherwise applicable full requirements tariff;
- The energy rates for standby service should not be different than the energy rates for analogous full requirements service;
- Supplemental service should be priced on par with other full requirements service;
- Maintenance service should be priced less than backup service because scheduling and advance notice imposes less costs.

Q DO YOU AGREE WITH MS. STEWARD'S ASSUMPTION THAT STANDBY CUSTOMERS REQUIRE 100% OF THEIR CONTRACT DEMAND FOR TRANSMISSION CAPACITY?

A No. This contention must be rejected because it is in direct violation of FERC guidelines. It is also contrary to use of the 12CP method to allocate transmission plant to full requirement customers. In fact, PacifiCorp also uses the 12CP method in developing its OATT. Thus, while ostensibly agreeing that the standby customers do not use the transmission system differently from other customers, it is for standby customers – and only standby customers – that Ms. Steward discards the notion of coincidence factors for transmission plant. The result of her design we would have to believe that a 10 MW standby customer places more coincident demand on the transmission system, rather than less, then a 10 MW full requirements customer.

Q HAS MS. STEWARD PRESENTED ANY STUDIES THAT WOULD INDICATE THAT STANDBY USE OF PACIFICORP'S TRANSMISSION SYSTEM IS BASED ON 100% OF CONTRACTED DEMAND?

A No, she has not. She has simply made an unsubstantiated and inappropriate assumption that standby customers' use of the transmission system is identical to their use of, say, a dedicated transformer.

<u>The Appropriate Cost Basis for Standby Service</u>

Q HOW SHOULD PRODUCTION AND TRANSMISSION COSTS BE DETERMINED FOR STANDBY CUSTOMERS?

A I recommend the Expected Value ("EV") method for both production and transmission costs. Under this method, the amount of reserve capacity required to provide standby service is equal to the product of the EFOR and the standby contract capacity.

Q WHY IS THE EV METHOD APPROPRIATE?

A This method is most consistent with FERC Order No. 69 in that it directly measures the probability that standby customers will or will not contribute to the need for, and use of, utility capacity. The EFOR directly reflects the probability that an outage will occur in any given hour.

The EV method is the most commonly used approach to quantify standby capacity requirements, according to the Edison Electric Institute.[4] To the best of my knowledge, this method was used to develop backup rates in Colorado, Florida, Georgia, Illinois, Massachusetts, Mississippi and Texas.

Q WHAT SHOULD BE USED AS A FORCED OUTAGE RATE IN CONNECTION WITH THE EV METHOD?

A The EFOR should reflect the long run performance of customer-owned generation facilities. However, RMP could not provide any information specific to the performance of SGC facilities on its system. It did refer us to Chapter 6 of its 2013 IRP for reference data. Page 125 presents a table of generating unit characteristics and shows an expected EFOR of 3% for gas turbines and similar generation facilities. RMP could have used this information. Instead, it used a proxy EFOR of 13% - based on its own generation fleet.

[4]"Standby Rates: Methods and Descriptions," Edison Electric Institute Rate Regulation Department, April 1991.

Q IS THERE ANY OTHER EVIDENCE QUANTIFYING THE LONG-TERM EFOR OF SELF-GENERATION?

A Yes. The Gulf Coast Cogeneration Association ("GCCA")—now known as the Gulf Coast Power Association—conducted a survey in 1991 of 56 installations in Texas and 18 installations in Louisiana, and determined that the 1990 combined and lifetime median availabilities were 95% and 94.8%, respectively. Because availability also includes scheduled maintenance outages, it follows that the EFORs of the self-generating facilities surveyed by the GCCA would be lower than 5%.[5] In a more recent survey, the Gas Research Institute ("GRI") concluded that cogeneration units had EFORs less than 6%.[6] Houston Lighting & Power Company ("HL&P") also surveyed the reliability of QF's in its service territory. The results showed an average EFOR of 5%.[7] However, this survey ignored several of the largest non-utility generators in HL&P's service territory. When corrected to include these generators, the average EFOR was only 3.1%.[8]

All of these studies support the use of an EFOR of significantly less than 13% when applying the EV method. To avoid overcharging highly

[5]"Survey of Cogeneration in Texas and Louisiana," Gulf Coast Cogeneration Association, October 23, 1991.

[6]"Reliability of Natural Gas Cogeneration Systems Final Report January 1990 - September 1992," GRI, September 1992.

[7]"Direct Testimony of James N. Purdue," Docket No. 12065; Houston Lighting & Power Company.

[8]Id. "Direct Testimony of Jeffry Pollock."

reliable SGCs, I recommend using 3% in applying the EV method for purposes of this case.

Q HOW WOULD USE OF A HIGH EFOR OVERCHARGE THE MORE RELIABLE COGENERATORS?

A The EFOR is used to determine the expected use of the generation and transmission system by the standby customer. If, for example, 5% is used for the average, and all standby customers have to pay a reservation charge based on an assumed 5% EFOR, then a customer with a lower (better) EFOR will be paying for more capacity than is necessary to meet its expected demand.

Q HOW CAN THIS BE AVOIDED?

A This could be avoided by eliminating the reservation charge altogether, and simply charging standby customers based on a daily proration of the demand charge when the customer actually utilizes standby service. This has generally not been adopted because of the desire to provide some ongoing compensation to the utility in connection with standby service, and because adoption of a specific reservation charge provides a quantification of standby revenues which can be used as revenue credits to the FR customer classes. In this regard, the standby charge sometimes is analogized to a premium for an insurance policy that provides coverage when needed.

Given this approach, it is imperative that the EFOR used to do the costing not be set excessively high. In this context, a 3% EFOR is a reasonable assumption. Facilities which experience higher forced outage rates (either routinely or in a particular year) will contribute additional revenues by virtue of the application of the daily prorated demand charge. With this approach, the amount of revenues collected for back-up service increases proportionately with the use of the system. This is appropriate because the additional usage contributes to a higher probability of the imposition of load at the time of the system peaks. Thus, the approach I recommend avoids overcharging highly reliable SGCs and insures that SGCs with higher EFORs pay a proper amount.

Q HAVE YOU QUANTIFIED THE CAPACITY-RELATED COSTS ASSOCIATED WITH FIRM STANDBY SERVICE?

A Yes. The analysis is shown in UIEC Exhibit COS 2.8 (MEB-8). The calculations are in the same format as the workpapers for RMP's development of its proposed Rate 31. To eliminate the differences that are due solely to revenue requirement and class allocation, so as to focus on rate design concepts, I have developed my rate based on RMP's claimed unit costs.[9]

---

[9]Were I to base the rates on my preferred 4CP study, the charges would be lower.

The first step was to derive a cost-based standby Reservation charge. The standby Reservation charge is comprised of:

- Production;
- Transmission; and
- Primary distribution.

The production and transmission components of the Reservation charge are derived by multiplying the unit cost times the EFOR and adjusting for the applicable loss factor by delivery voltage. To minimize controversy, I have accepted the generation unit costs derived by the Company and used by Ms. Steward.

Q WHAT DID YOU USE AS A BASIS FOR THE TRANSMISSION COMPONENT OF THE RATE?

A Based on Dr. Lesser's testimony, I have used the OATT charge of \$2.15/kW-month.

Q WHY DID YOU USE THE SAME GENERAL METHOD TO CALCULATE THE PRODUCTION AND TRANSMISSION COMPONENTS OF THE STANDBY RESERVATION CHARGE?

A This treatment is consistent with the fact that RMP uses coincident demands to apportion responsibility for transmission costs. It also recognizes the fact that the same demands, which give rise to the need for production capacity, also drive the need for transmission investment.

Q HOW WAS THE PRIMARY DISTRIBUTION COMPONENT OF THE STANDBY RESERVATION CHARGE CALCULATED?

A It was calculated using the same methodology as RMP. It appropriately recognizes the fact that there is not as much diversity at the distribution level than either the production or transmission level because distribution facilities are electrically closer to the customer.

Q WHAT IS THE NEXT STEP IN DETERMINING THE CAPACITY-RELATED COSTS OF PROVIDING STANDBY SERVICE?

A On average, the Reservation charge recovers the capacity cost of providing standby. When more than the average amount of standby service is required in a particular billing period, it would be appropriate to require the customer to pay additional charges to recognize the higher cost of providing service. For example, if an outage were to last an entire month, a standby customer would resemble an FR customer. To avoid charging more for standby service than for FR service, it would be appropriate to develop Daily Demand charges for backup and maintenance power service. This also is shown in UIEC Exhibit COS 2.8 (MEB-8).

The process illustrated in this exhibit is similar to the one used by Ms. Steward in deriving Daily Demand charges for backup and maintenance power service. The starting point in both analyses is the proposed demand cost and demand charges. For backup power, the Daily Demand cost would be the total monthly demand charge, minus the standby charges, divided by the number of days in a calendar month. In other words, the Daily Demand charge for backup power service would prorate the monthly capacity-related costs on a daily basis.

Q WHEN WOULD THE DAILY DEMAND CHARGE APPLY?

A Because my standby charge is developed using a 3% EFOR, it includes the use of standby service for about one day per month (30 days per month x 3%). Accordingly, if a customer used standby service for one day or a fraction of a day, there would be no additional charge. Additional charges would apply for every day or a portion thereof beyond one day per month.

Q PLEASE EXPLAIN HOW MAINTENANCE POWER CHARGES SHOULD BE DETERMINED.

A The Daily Demand cost for maintenance power service is lower than the corresponding backup power charge. As described earlier, backup power is more likely to be coincident with RMP's critical summer system peak demands than maintenance power. In addition, maintenance power is a lower quality of service than backup power because it must be pre-scheduled and can be denied by RMP.

Not only is maintenance power a lower quality of service than backup power, it is also a lower quality of service than firm service provided during off-peak hours because the former must be scheduled in advance and is conditioned on resource adequacy. No such conditions apply to firm service. For these reasons, the Daily Demand charge for maintenance power service should be significantly below the corresponding backup power Daily Demand charge.

Q WHAT WOULD BE A COST-BASED DAILY DEMAND CHARGE FOR MAINTENANCE POWER?

A Recognizing the requirement to schedule the use of maintenance power with RMP, I agree with Ms. Steward that the Daily Demand charge for maintenance power should not exceed 50% of the corresponding backup power Daily Demand charge.

Q WHAT MAINTENANCE PROVISIONS SHOULD BE AVAILABLE?

A The maintenance provision should allow for flexible scheduling by mutual agreement with RMP, in amounts and for times sufficient to allow SGCs to properly maintain their generation equipment.

Q DO YOU BELIEVE THAT RMP'S PROPOSED MAINTENANCE PROVISION IS SUFFICIENT FOR THIS PURPOSE?

A No, I do not. RMP's tariff indicates that maintenance can be scheduled for a maximum of 30 days per year, either taken in one continuous period or two consecutive 15-day periods. This may or may not accommodate the needs of individual SGCs. For example, if an SGC has two generating units, each may require more maintenance time than RMP's provision specifies. For example, a customer with two generating facilities may require twice as much time as a customer with a single generation facility. In addition, maintenance does not always conveniently happen to fall in pre-specified time intervals of fixed duration. Some maintenance needs may arise during the course of the year and there is no reason that the standard provision should not allow that to occur.

Q DO YOU HAVE A RECOMMENDED ALTERNATIVE?

A Yes. I recommend that customers be allowed 30 days per year of scheduled maintenance for each generation unit, to be taken at times mutually agreed to between the customer and RMP. This type of provision adds flexibility and will discourage RMP from wanting to point to the specifics of its tariff as a limitation on what it is willing to allow customers to do.

Q HAVE YOU PREPARED A TARIFF BASED ON YOUR RECOMMENDATIONS?

A Yes. This is shown in UIEC Exhibit COS 2.9 (MEB-9) as a red-line change to RMP's proposed Schedule 31.

Q HAVE BAI CONSULTANTS RECENTLY PARTICIPATED IN PREPARATION OF A REPORT ON STANDBY RATES WITH THE REGULATORY ASSISTANCE PROJECT ("RAP")?

A Yes. This report presents general principles for standby rates and included a review of standby rates in five states, including Utah. As a part of this process, a workshop was held at the PSC on November 28, 2012. A copy of this report is included UIEC Exhibit COS 2.10 (MEB-10).

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and President of the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation I was employed by the Utilities Section of the Engineering and Technology Division of Esso Research and Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of New Jersey.

In the Fall of 1965, I enrolled in the Graduate School of Business at Washington University in St. Louis, Missouri. I was graduated in June of 1967 with the Degree of Master of Business Administration. My major field was finance.

From March of 1966 until March of 1970, I was employed by Emerson Electric Company in St. Louis. During this time I pursued the Degree of Master of Science in Engineering at Washington University, which I received in June, 1970.

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income. I have also addressed utility resource planning principles and plans, reviewed capacity additions to determine whether or not they were used and useful, addressed demand-side management issues independently and as part of least cost planning, and have reviewed utility determinations of the need for capacity additions and/or purchased power to determine the consistency of such plans with least cost planning principles. I have also testified about the prudency of the actions undertaken by utilities to meet the needs of their customers in the wholesale power markets and have recommended disallowances of costs where such actions were deemed imprudent.

I have testified before the Federal Energy Regulatory Commission (FERC), various courts and legislatures, and the state regulatory commissions of Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri, Nevada, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin and Wyoming.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business.

Brubaker & Associates, Inc. and its predecessor firm has participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

An increasing portion of the firm's activities is concentrated in the areas of competitive procurement. While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas and a licensed electricity aggregator in the State of Texas.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

\\Doc\Shares\ProlawDocs\TSK\9868\Testimony-BAI\259124.doc