BEFORE THE

PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations	))))))))))	**Docket No. 11-035-200**

Direct Testimony and Exhibits of

Maurice Brubaker

on Cost of Service and Revenue Allocation Issues

On behalf of

Utah Industrial Energy Consumers

June 22, 2012

BRUBAKER & ASSOCIATES, INC.

Project 9564

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Direct Testimony 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 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"). Members of UIEC 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 and revenue allocation issues.

Q WHAT IS THE RELATIONSHIP OF YOUR TESTIMONY TO THAT OF DR. JONATHAN LESSER, WHO ALSO ADDRESSES COST OF SERVICE 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 load shapes, class load shapes and the growth in demand by the major customer classes.

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

Q WHAT IS THE CENTRAL POINT OF THE UIEC POSITION IN THIS 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 principals 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 summer peak loads 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 not only should be recognized in the class cost of service studies, but also should be recognized explicitly in the base calculations for the EBA, in the monthly tracking of the variable cost component of the EBA, and in the EBA reconciliation process. Monthly EBA tracking is consistent with the Commission’s June 15, 2012 Order issued in Docket No. 09-035-15.

Q PLEASE SUMMARIZE YOUR SPECIFIC FINDINGS AND RECOMMENDATIONS?

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

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.

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.

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.

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

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

8. 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.

9. The facts 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.

10. 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.

11. Exhibit UIEC ____ (MEB-5), page 1, shows the step-by-step process to translate the PacifiCorp level of monthly variable costs into monthly costs for Utah, and also into the class cost allocation model.

12. Exhibit UIEC ____ (MEB-5), page 2, shows the variable component of monthly NPC and demonstrates that the RMP class cost of service studies fail to preserve the important monthly differences in costs.

13. 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. Exhibit UIEC ____ (MEB-6) presents a summary of my cost of service studies (shown on Exhibits UIEC ____ (MEB-7) to UIEC ____ (MEB-12) that are based on summer peak loads. They all show that Schedule 9 customers either deserve a decrease, or require only a small increase, to move rates to cost of service.

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. 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. This would preclude 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.

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. Exhibit UIEC ____ (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 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 Exhibit UIEC ____ (MEB-2), the Utah jurisdiction exhibits an even more pronounced summer peaking characteristic than the system.

Residential and Small Commercial Loads <u>Cause the Summer Peaking Load Shape</u>

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

A It is predominately the growth in summer loads in Utah, driven principally by the growth in residential summer peak loads. In Docket No. 07-035-93, RMP witness Dr. Rife explained this phenomena at page 14 of his testimony as follows:

> "Prior to 1999, the system as a whole peaked during the winter months. Because of the growth in Utah, the Company has started to experience summer peaks and expects this pattern to continue in the future. This is evident in Utah state growth rates. From 2002 through 2006, while the energy growth in Utah averaged 3.2 percent per year, the summer peak average growth rate was 3.4 percent."

Q DID DR. RIFE EXPLAIN WHY THE SUMMER PEAK LOADS ARE GROWING IN RELATION TO LOADS IN OTHER MONTHS?

A Yes. He discussed this at some length beginning on page 13 of the referenced testimony. Beginning at line 294, he observed as follows:

> "During the last decade, Utah homes on average have increased in size. As the growth continues, the Company expects the average size of homes to further increase. Additionally, the Company is seeing more homes that have Central Air Conditioners (CAC). Customers across our Utah service territory are seeking more comfortable living conditions and seem to be willing to pay for them. CAC are becoming the norm for space conditioning on hot summer days. More new homes require CAC as a selling point. Customers with Evaporative Air Conditioners (EAC) are changing their equipment to keep up with the norm."

Q HAVE YOU REVIEWED HOW THE CONTRIBUTIONS OF THE VARIOUS CUSTOMER CLASSES TO UTAH MONTHLY PEAKS HAS CHANGED OVER TIME?

A Yes. This information is presented in Exhibit UIEC ____ (MEB-3).

Q PLEASE EXPLAIN THIS INFORMATION.

A Exhibit UIEC ____ (MEB-3) shows the class contribution to system peak loads over the period 2004 through 2010. The contribution for each of the indicated classes is the average of their demands at the times of the July and August system peak loads.

Note that over the period 2004 through 2010 the contribution of the residential class has increased from a little less than 1,300 megawatts to 1,800 megawatts, an increase of 500 megawatts.

The Schedule 6 increase is from about 900 megawatts to almost 1,100 megawatts, and Schedule 9 has experienced an increase from about 425 megawatts to about 550 megawatts. Schedule 8 and 23 have exhibited very minor growth.

Q WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A The irrefutable conclusion is that the growth in summer peak loads is primarily attributable to the increase in demands at the time of the summer peak by the residential customer class. The increase in the contribution to summer peak loads by the residential class is far greater than the combined increases in contributions to the summer peak load by all of the other major customer classes.

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

A Yes. The graph on page 1 of Exhibit UIEC ____ (MEB-4A) shows the demands of each of the major classes at the times of the monthly system peaks, the graph on page 2 shows the demands on an hourly basis on the system peak day, and the graph on page 3 shows the load pattern over a weekly cycle.

Q PLEASE EXPLAIN THESE GRAPHS.

A Page 1 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.

Q WHAT IS SHOWN ON PAGE 2?

A Page 2 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, 2011) 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.

Page 3 shows the hourly loads during the peak summer week for the base year. The graph begins at midnight on August 8 and continues through midnight on August 14. 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 2,000 megawatts to over 3,500 megawatts, a swing of 1,500 megawatts, or more than 75% 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, 2011 TYPICAL, OR ARE THEY UNIQUE TO THIS PERIOD OF TIME?

A They are typical. For example, please see Exhibit UIEC ____ (MEB-4B) which presents comparable data for the 12 months ended December 2008. Obviously, the load patterns exhibited in the 12-month period ended June 30, 2011 are typical, and 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. Dr. Lesser discusses this and provides examples of such cost differences in his testimony.

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 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.

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 IRP), PacifiCorp expresses 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.]

Throughout the IRP document, 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.

As also noted on page 83 in the Chapter Highlights section, PacifiCorp forecasts an average load (energy) growth rate of about 1.8% per year, whereas it expects growth in the eastern system annual peak load to be at a rate of 2.4% per year, and the overall system peak to grow at a rate of 2.1% per year. The fact that the expected growth rate in summer peak demand exceeds the expected growth in energy sales indicates that the overall system load factor will be deteriorating, which will put additional upward pressure on rates. This further underscores the importance of summer peak loads from a cost allocation and rate perspective.

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 pages 199 and 200 of Chapter 7 – Modeling Approach, PacifiCorp explains:

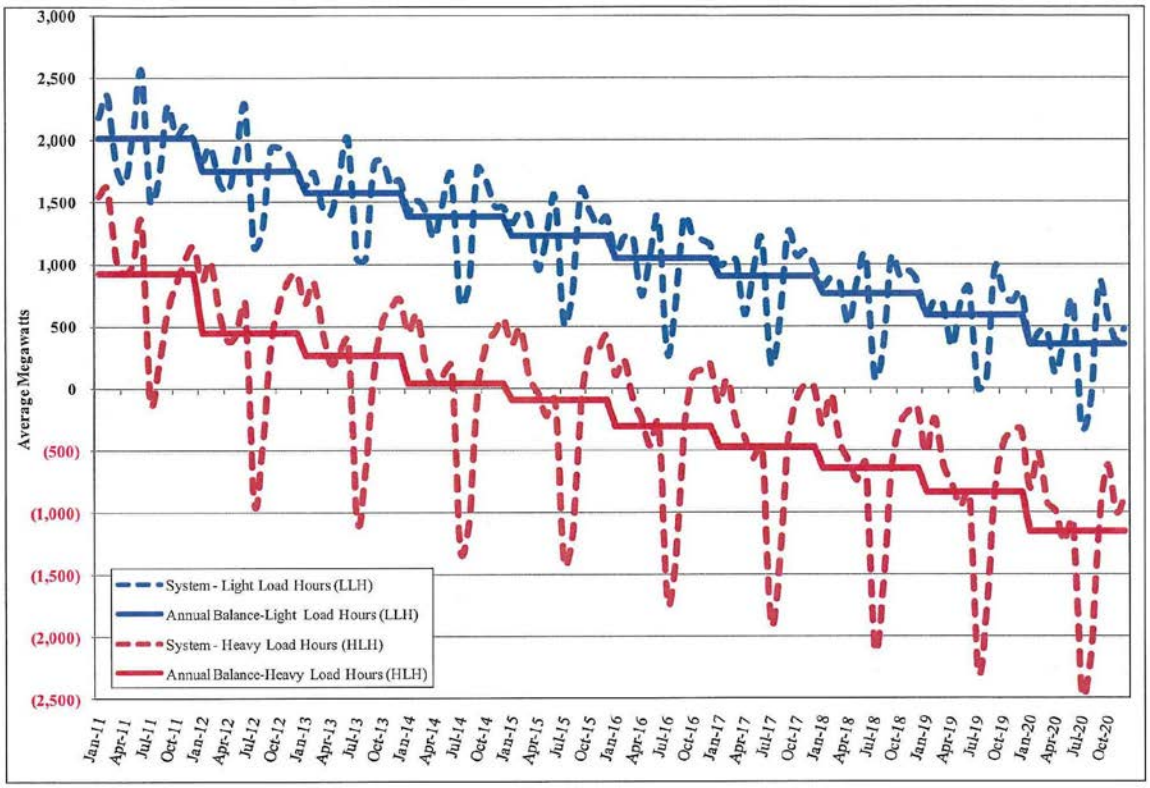
> "**Loss of Load Probability**
> Loss of Load Probability is a term used to describe the probability that the combinations of online and available energy resources cannot supply sufficient generation to serve the load peak during a given interval of time. For reporting LOLP, PacifiCorp calculates the 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 Chapter 8, 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 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.

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

A Yes, it did. This appears in graphical format at page 105. Figure 5.6 – "System Average Monthly and Annual Energy Positions" has been extracted and appears below in the text of my testimony.

Figure 5.6 – 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 light load hours ("LLH") and for heavy load hours ("HLH"). On the graph the upper lines pertain to LLH, and the lower lines pertain to HLH. The solid lines indicate the annual average position while the dashed lines indicate the monthly positions.

Deficits are indicated by the negative values (the lower part of the graph), and over the entire planning horizon, without any capacity additions, there is not expected to be any shortfall during the LLH prior to 2020. Because all of the monthly values for

LLH are above zero, it is clear that energy requirements are not driving any capacity additions.

Q WHAT DOES THE HLH SECTION OF THE GRAPH INDICATE?

A It indicates that there are deficits in the high load hours for the peak months beginning in 2011, and growing dramatically each year out to 2020. Note that these large deficits are confined to the summer peak period. There actually are surpluses during HLH in non-peak months.

Q WHAT DO THESE ANALYSES INDICATE ABOUT THE IMPORTANCE OF SUMMER PEAK LOADS?

A This assessment clearly shows that deficits are occurring now and into the future, but only in the high load hours of the summer months. Deficits never appear in the low load hours in any month until the summer of 2020, by which time summer peak loads will have caused the need for the addition of over 3,800 megawatts of resources.

Q IS THERE ADDITIONAL EVIDENCE TO CORROBORATE THIS CONCLUSION?

A Yes. In response to Data Request No. DPU 6.39, 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 <u>critical summer months</u>" [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.

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

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 20% to 48% higher than the winter prices. For Schedule 6, the

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

demand rates in the summer are 25% higher than the demand rates in the winter, and the energy charges in the summer are 8% higher than the energy charges in the winter. 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 clean 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 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.' "

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**

[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.

> **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.

<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 VARY SEASONALLY?

A Yes, as more fully discussed in Dr. Lesser's testimony, variable costs also vary 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.

Q PLEASE DESCRIBE THAT METHODOLOGY.

A The allocation, which I have summarized on page 1 of Exhibit ____ UIEC (MEB-5), begins with the PacifiCorp total NPC by month. For the variable components, costs are allocated to Utah on a monthly basis using the monthly relationship between sales to Utah customers and total sales. Each monthly allocated Utah cost is scaled by a small factor so that the sum of the 12 monthly costs allocated to Utah equals the annual cost allocated by RMP to Utah in its filed cost study. The monthly scaling factors differ by FERC account and range in value from 98.38% to 101.07%.

Then, monthly Utah costs are allocated monthly to customer classes using the same approach as was used to allocate costs from total Company to Utah. That is, variable costs are allocated monthly using the relationship between each class's monthly kWh to total Utah kWh.

For each FERC account identified, the allocated costs by month are summed for each class and divided by the total Utah costs to derive a single class allocation factor specific to that FERC account variable cost. These specific account allocation factors are then applied in the class cost of service model to allocate the Utah costs to each class.

Q HAVE YOU PREPARED A COMPARISON OF THE VARIABLE COST COMPONENT OF YOUR MONTHLY NPC VALUES TO THOSE THAT ARE INHERENT IN RMP'S NPC?

A Yes. Please see page 2 of Exhibit UIEC ____ (MEB-5).

Q PLEASE EXPLAIN THIS EXHIBIT.

A The first section of the exhibit shows the variable cost components of total Company NPC from RMP witness Duvall's NPC exhibit. Shown are the dollar amounts, the MWh, the dollar amount per MWh, and an index which indicates the relationship between the average cost in each month and the annual average cost. Note that costs in the summer are greater than the average annual cost.

The second section identifies the per MWh cost allocated to Utah by RMP witness Paice and shows the monthly values indexed to the annual average. Note that the average cost for each month is the same as the annual cost. Mr. Paice does not account for any seasonal variation in his allocation to Utah. This approach has the effect of removing the seasonality of the costs and effectively socializes the higher summer prices across all months to the detriment of high load factor and off-peak customers. This is clearly not consistent with cost-causation and should be changed.

The third section of the exhibit shows the results of the adjustment which I have made in order to more closely preserve the seasonal distinctions in power costs for purposes of application in the class cost of service study. Note that the summer prices are consistently above the average which is consistent with the total Company NPC relationship shown in the first section of this exhibit.

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 base 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. I have prepared several different studies that utilize summer peak demands. While I believe that the test year load characteristics clearly point to the use of a 2CP allocation method, I have also presented the allocation study based on 3CP and 4CP.

And, although I firmly believe that all fixed costs should be allocated strictly on class demands without any energy weighting, for illustrative purposes, I have prepared versions of these studies with a 25% energy weighting. The results for Schedule 9 are summarized and compared to RMP's study on Exhibit UIEC ____ (MEB-6). The following table summarizes these studies and identifies them by exhibit number.

No. of Peaks	Percent of Fixed Costs Allocated on Demand	Percent of Fixed Costs Allocated on Energy	Exhibit No.
2	100%	0%	UIEC ____ (MEB-7)
3	100%	0%	UIEC ____ (MEB-8)
4	100%	0%	UIEC ____ (MEB-9)
2	75%	25%	UIEC ____ (MEB-10)
3	75%	25%	UIEC ____ (MEB-11)
4	75%	25%	UIEC ____ (MEB-12)

Q PLEASE DESCRIBE THESE EXHIBITS.

A The exhibits each consist of two pages and are in the same format as Exhibit RMP___ (CCP-1). The first page of the exhibit shows the adjustments at current rate levels to move each customer class to the system average rate of return at present rates. Page 2 of each exhibit shows the adjustment from current rate levels to the revenues required to produce the claimed 7.91% target rate of return at proposed rates.

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

A Comparing the results for Schedule 9 to the results produced by RMP's cost of service study, it is obvious that 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.

EBA Considerations

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 during the EBA pilot period as a possible modification.

The Consolidated Model

Q ARE YOU ABLE TO RUN YOUR CLASS ALLOCATION PROPOSAL THROUGH THE CORRECTED VERSION OF THE CONSOLIDATED MODEL THAT DR. JIM LOGAN PREPARED FOR THE COMMISSION?

A No. The consolidated model, even as corrected, has an error in the formulas used to develop Factor 12 on the "Sch Fac" sheet, cells E119:O123. For example, in cell E119, the formula is:

=E85*PKJAN+F85*PKFEB+G85*PKMAR+H85*PKAPR+I85*PKMAY+
J85*PKJUN+K85*PKJUL+L85*PKAUG+M85*PKSEP+N85*PKOCT+
O85*PKNOV+P85*PKDEC

Note that cell E85 references a June value but is multiplied by the January value "1" from cell D9 of the "Vars" sheet; cell F85 references a July value and is multiplied by the February value "1", etc., etc. This does not cause an error in the default results since this is a 12CP study and all monthly values are "1". However if, for example, a 4CP or 2CP scenario was desired, the above mentioned formulas would all have to be corrected and all other formulas dependent upon the values PKJAN, PKFEB, etc. would have to be verified and adjusted appropriately. If just a class (SAM) 4CP, 2CP, etc. was required, a column equivalent to cells D9:D20 would have to be included in the SAM section (Column K) of the "Vars" sheet. In contrast, the RMP model (Paice) allows for simple adjustment on the "Input" sheet to change from a class 12CP study to a 4CP, 2CP, etc. study.

Q DOES THE CONSOLIDATED MODEL DIFFER FROM RMP'S MODEL IN THE WAY IT CAN BE USED TO ALLOCATE COSTS MONTHLY?

A Yes. RMP's class model (Paice) uses the 2010 Protocol method for jurisdictional and distribution functional factors and a 2010 Protocol (non wtg) method for COS factors. The consolidated model replicates RMP's jurisdictional and class COS results. But, RMP's model provides several alternative cost allocation methods which can be easily selected on the "Input" sheet of the model. One feature in RMP's model, that is not incorporated in the consolidated model, is a weighting option which utilizes NPC factors developed within the model (the "NPC Factors" sheet). These features can be used to allocate FERC accounts 447, 501, 503, 547, 555 and 565 on a monthly basis. No such option is apparent in the consolidated model, nor is the data to duplicate RMP's NCP factors contained in the model. As a result, the consolidated

Logan model cannot be used to allocate energy costs monthly, only an annual option is available.

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.

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